Synapse
Energy Economics, Inc.

Avoided Energy Supply Costs in New England:

2011 Report

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PREPARED FOR

Avoided-Energy-Supply-Component (AESC) Study Group

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Table of Contents

Table of Exhibits

Chapter 1: Executive Summary

This 2011 Avoided-Energy-Supply-Component Study ("AESC 2011," or "the Study") provides projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England. All reductions in use referred to in the Study are measured at the customer meter, unless noted otherwise.

AESC 2011 provides estimates of avoided costs for program administrators throughout New England to support their internal decision-making and regulatory filings for energy efficiency program cost-effectiveness analyses. The AESC 2011 project team understands that, ultimately, the relevant regulatory agencies in each state: specify the categories of avoided costs that program administrators in their states are expected to use in their regulatory filings, and; approve the values used for each category of avoided cost.

In order to determine the value of those programs, projections of avoided electric capacity and energy prices have been developed for a hypothetical future, the "Reference Case," in which no new energy efficiency is implemented from 2012 onward. It is important to note that the projections in AESC 2011 should not be interpreted as projections of or proxies for the market prices of natural gas, electricity, or other fuels at any future point in time, for the following two reasons. First, the projections of electric capacity and energy prices are for a hypothetical future and thus do not reflect the actual market conditions and prices likely to prevail in an actual future with significant amounts of new efficiency measures. Second, the Study is providing projections of the avoided costs of these fuels in the long-term. The actual market prices of those fuels at any future point in time will vary above and below their long-run avoided costs due to the various factors that affect short-term market prices at any point in time.

AESC 2011 updates the 2009 AESC Study ("AESC 2009") to reflect changes in observed facts and in expectations regarding future market conditions and future costs. Specific changes in expectations that contribute to changes from the AESC 2009 avoided costs are projections of:

- Dramatic increases in the quantity of technically recoverable shale gas resources—coupled with decreases in the expected costs of finding, developing, and producing gas from those resources—leading to lower projections of avoided costs for natural gas and gas-fired electric energy;
- Retirements of a significant quantity of existing generating capacity, leading to higher estimates of avoided costs for electric capacity;
- A delay in the start of federal regulation of carbon emissions from 2013 to 2018, leading to lower projections of avoided costs for electric energy; and

- Lower avoided costs of gas distribution margins, leading to lower projections of avoided costs for natural gas delivered to end users.

The Study provides detailed projections of avoided costs by year for an initial 15 year period, 2012 through 2026, and extrapolated values for another 15 years, from 2027 through 2041. All values are reported in 2011 dollars ("2011$") unless noted otherwise. For ease of reporting and comparison with AESC 2009, many results are expressed as levelized values over 15 years.[1] These levelized results are calculated using the real discount rate of 2.46 percent solely for illustrative purposes.

1.1. Background to Study

AESC 2011 was sponsored by a group of electric utilities, gas utilities, and other efficiency program administrators (collectively, "program administrators" or "PAs"). The sponsors, along with non-utility parties and their consultants, formed an AESC 2011 Study Group to oversee the design and execution of the report. The Study sponsors include: Berkshire Gas Company; Cape Light Compact; National Grid USA; New England Gas Company; NSTAR Electric & Gas Company; New Hampshire Electric Co-Op; Columbia Gas of Massachusetts; Northeast Utilities (Connecticut Light and Power, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas); Unitil (Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc., and Northern Utilities); United Illuminating; Southern Connecticut Gas and Connecticut Natural Gas; Efficiency Maine; and the State of Vermont. The non-utility parties represented in the Study Group include: Connecticut Energy Conservation Management Board; Massachusetts Department of Public Utilities; Massachusetts Department of Energy Resources; Massachusetts Attorney General; Massachusetts Low-Income Energy Affordability Network ("LEAN"); Massachusetts Energy Efficiency Advisory Council; New Hampshire Public Utilities Commission; and Rhode Island Division of Public Utilities and Carriers.

The AESC 2011 Study Group specified the scope of work, selected the Synapse Energy Economics ("Synapse") project team, and monitored progress of the study. The Synapse project team presented its analyses and projections to the 2011 AESC Study Group in eight substantive tasks.

The draft deliverable for each task was reviewed in a conference call. The relationship between the chapters in this report and the task deliverables is as follows:

- Chapter 2 – Methodologies and Assumptions Underlying Projections of Avoided Electric Supply Costs (Task 3);

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[1] 15 year levelization periods of 2010-2024 for AESC 2009 and 2012-2026 for AESC 2011.

- Chapter 3 – Wholesale Natural Gas Prices (Task 4);
- Chapter 4 – Avoided Natural Gas Costs (Task 6);
- Chapter 5 – Forecast of New England Regional Oil Prices and Avoided Costs of Other Fuels by Sector (Tasks 5 and 9);
- Chapter 6 – Regional Electric Energy Supply Prices Avoided by Energy Efficiency and Demand Response Programs (Task 7);
- Chapter 7 – Sensitivity Analyses (Task 8);
- Chapter 8 – Usage Instructions (Task 10).

The report was prepared by a project team assembled and led by Synapse. Synapse's Rick Hornby and Max Chang managed the project. Dr. Carl Swanson of the Swanson Energy Group led the analysis of avoided natural gas costs. Paul Chernick of Resource Insight led the analysis of wholesale capacity costs and Demand Reduction Induced Price Effect ("DRIPE"). Dr. David White and Nichole Hughes of Synapse developed the projections of wholesale electric energy prices. Jason Gifford and Bob Grace of Sustainable Energy Advantage ("SEA") provide estimates of renewable energy credit ("REC") demand, supply, and price. Dr. David White and Matt Wittenstein of Synapse developed projections of avoided costs of other fuels. Rachel Wilson, Matt Wittenstein, and Bruce Biewald of Synapse developed externality values for air emissions avoided due to reductions in electricity and fuel use.

1.2. Avoided Costs of Electricity to Retail Customers

An electric energy efficiency program that enables a retail customer to reduce his or her peak and annual electricity use has a number of key monetary and environmental benefits. Major categories of benefits include:

- Generation capacity and energy costs avoided due to reductions in quantities required to meet electric energy demand. *Electric capacity costs* are avoided due to a reduction in the annual quantity of electric capacity that load serving entities ("LSEs") will have to acquire from the Forward Capacity Market ("FCM") to ensure an adequate quantity of generation during hours of peak demand. *Electric energy costs* are avoided due to a reduction in the annual quantity of electric energy that LSEs will have to acquire. These avoided costs include a reduction in the cost of renewable energy incurred to comply with the applicable Renewable Portfolio Standards ("RPS");[2]

[2] Electric energy is measured in kilowatt hours (kWh) or megawatt hours MWh; electricity capacity is measured in kilowatts (kW) or megawatts (MW).

- Generation capacity and energy costs avoided due to reductions in wholesale market prices required for capacity and energy. Reductions in the quantities of capacity and of energy being acquired from those markets will cause prices in those markets to decline relative to Reference Case levels for a certain period of time, after which responses by market participants will lead to a shift in the supply curve and cause prices to rise back towards the Reference Case levels. AESC 2011 refers to the reduction or mitigation of market prices due to reductions in demand for capacity and energy as capacity DRIPE and energy DRIPE, respectively.
- Environmental externality costs avoided due to a reduction in the required quantity of electric energy that has to be generated. An environmental externality is the value of an environmental impact associated with the use of a product or service, such as electricity, that is not reflected in the price of that product. AESC 2011 uses the long-term abatement cost of carbon dioxide emissions as a proxy for these externalities.
- Local transmission and distribution ("T&D") infrastructure costs avoided due to a reduction in the timing and/or size of new projects that have to be built, resulting from the reduction in electric energy that has to be delivered.

AESC 2011 provides estimates of each category of avoided costs except avoided T&D, which is utility-specific and beyond the scope of the study. The projected avoided costs are provided by geographic area, by year, and by costing period within each year. These components are:

- **Avoided energy.** This is the largest component. It consists of the wholesale electric energy price, the REC cost, and a wholesale risk premium. Levelized annual avoided energy costs are approximately 17 percent lower on average than those in AESC 2009. The levelized annual wholesale electric energy costs are lower primarily due to projections of lower natural gas prices and a delay in Federal regulation of carbon emissions. The decline in that component is offset somewhat in summer peak periods by lower efficiency gas-fired units setting market prices due to an increase in the quantity of existing capacity projected to retire.
- **Avoided capacity.** Avoided capacity costs consist of revenue from demand reductions bid into the FCM and the value of generating capacity avoided by demand reductions that are not bid into the FCM. Levelized annual avoided capacity costs for demand reductions bid into the FCM are approximately 91 percent higher than AESC 2009. This increase is primarily due to the extension of floor prices through Forward Capacity Auction ("FCA") 6, the exclusion of reductions in demand from existing efficiency, and higher projections of new

capacity additions due to the increased quantity of existing capacity projected to retire.

- **Energy DRIPE.** This is the value of the reduction in energy market prices due to kWh reductions. Levelized annual intrastate energy DRIPE values are approximately 43 percent higher on average than AESC 2009, primarily due to changes in wholesale energy prices from AESC 2009 offset by changes in the DRIPE dissipation factor for new generation.
- **Capacity DRIPE.** This is the value of the reduction in capacity market prices due to kW reductions. Levelized annual capacity DRIPE values are approximately 370 percent higher on average than AESC 2009 due to projections of higher capacity prices and a longer dissipation period.
- **Avoided CO_2 environmental externalities.** This is the cost of controlling CO_2 emissions not reflected in wholesale energy market prices. Levelized annual values are approximately 16 percent higher due to the five-year delay in federal regulation of CO_2 emissions and higher modeled emission rates compared to two years ago.

The relative magnitude of each component for the summer peak costing period is illustrated in Exhibit 1.1 for an efficiency measure with a 55 percent load factor implemented in the West Central Massachusetts zone ("WCMA").

Exhibit 1-1: Illustration of Avoided Electricity Cost Components, AESC 2011 vs. AESC 2009 (WCMA Zone, Summer On-Peak, 15 Year Levelized Results, 2011$)

Component	AESC 2009	AESC 2011	Difference Relative to AESC 2009	
	cents/kWh	cents/kWh	cents/kWh	% Difference
Avoided Energy Costs	9.63	9.06	-0.57	-5.9%
Avoided Capacity Costs[1,2]	0.59	1.08	0.49	83.2%
Energy and Capacity Subtotal	**10.22**	**10.14**	**-0.08**	**-0.8%**
DRIPE				
Intrastate Energy[3]	2.76	3.18	0.43	15.4%
Capacity[2]	0.26	1.23	0.97	371.9%
DRIPE Subtotal	**3.02**	**4.41**	**1.39**	**46.1%**
Subtotal: Avoided Energy and Capacity + Intrastate DRIPE	**13.23**	**14.55**	**1.31**	**9.9%**
CO_2 Externality[4]	2.95	3.41	0.46	15.5%
Total	**16.19**	**17.96**	1.77	10.9%

Notes
-Values may not sum due to rounding
-Avoided energy costs for Summer On-Peak incorporate avoided REC costs (All Classes for AESC 2011, Class I for AESC 2009)
-AESC 2009 values levelized (2010-2024) escalated to 2011$
1) Avoided capacity costs assumes 100% ***selling*** into Forward Capacity Markets
2) Assuming a 55% load factor
3) Values are for Intrastate *energy* DRIPE
4) 2011 CO_2 prices and physical emission rates

For this costing location and period, AESC 2011 is projecting total avoided costs from direct reductions in energy and capacity of 10.2 cents per kWh, approximately 0.6 percent lower than the corresponding AESC 2009 total.

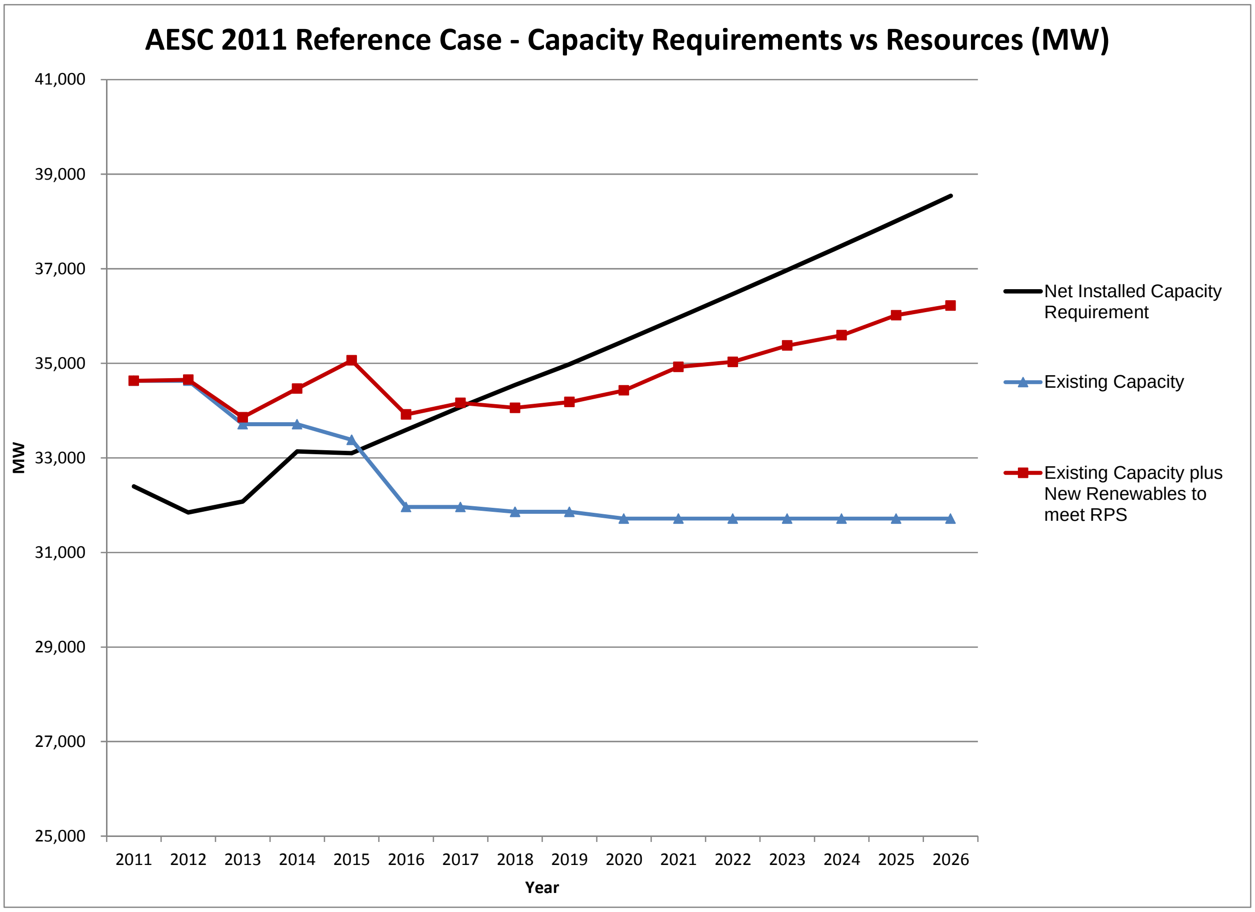
In total, the Study's projection of the avoided cost of energy and capacity reductions (10.16 cents per kWh), plus intrastate DRIPE and CO_2 externality, is 17.98 cents per kWh—about 11.1 percent higher than AESC 2009. The factors driving the differences between the AESC 2011 and AESC 2009 estimates are discussed by component below.

1.2.1. Avoided Capacity Costs

Avoided electric capacity costs are an estimate of the value of a reduction in energy use by retail customers during hours of system peak demand. The major input to this calculation is the avoided wholesale electric capacity cost. To develop an avoided cost at the meter, the avoided wholesale electric capacity cost is first increased by the reserve margin requirements forecasted for the year, then increased by eight percent to reflect ISO-NE losses.

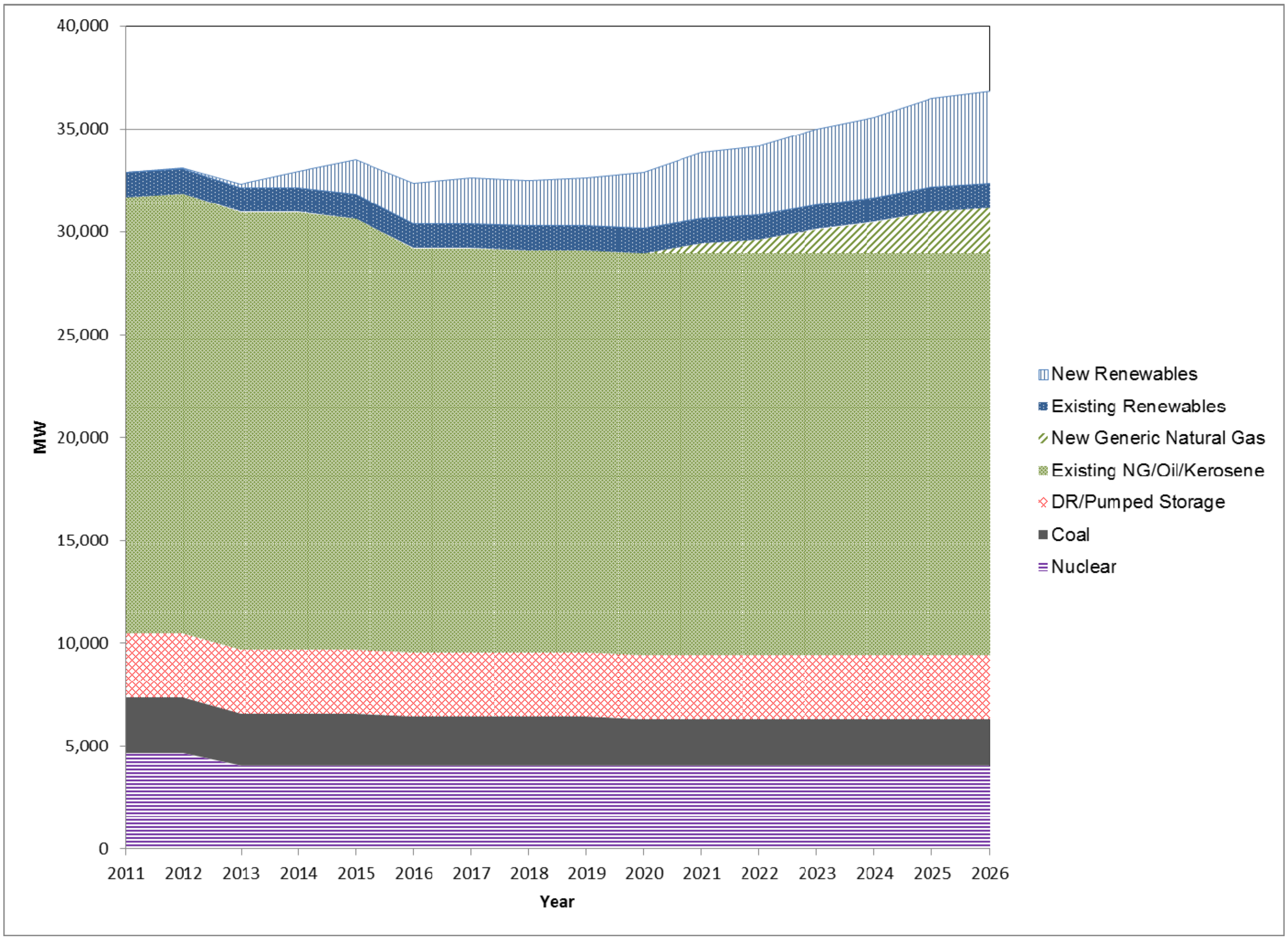
The major drivers of avoided wholesale capacity costs are system peak demand, retirements of existing capacity, new capacity from resources added to comply with RPS requirements, and new non-RPS capacity additions. AESC 2009 projected there would not be a need to add new capacity other than renewable resources until after 2024. In contrast, as indicated in Exhibit 1-2, AESC 2011 is projecting that new capacity, other than RPS-related renewable resources, will have to be added starting in 2020. This is for two main reasons.

Exhibit 1-2: AESC 2011 Capacity Requirements vs. Resources (Reference Case)



First, our Reference Case assumes approximately 2,000 MW more existing capacity will retire during the Study period than the AESC 2009 Reference Case assumed. The anticipated retirements include Vermont Yankee (600 MW) and over 1,000 MW at older coal plants that are facing significant costs to comply with tighter restrictions on air emissions under recent and impending changes in federal regulations. Second, the Reference Case assumes transmission constraints will prevent a portion of the capacity located in Maine from affecting the regional capacity market price until 2014. The AESC 2011 Reference Case capacity mix is presented in Exhibit 1-3.

Exhibit 1-3: AESC 2011 Reference Case, Capacity by Source (MW)



The 15 year levelized projections of capacity costs avoided by reducing purchases from the FCM from AESC 2011 and AESC 2009 are shown in Exhibit 1-4.

Exhibit 1-4: Avoided Electric Capacity Costs, AESC 2011 vs. AESC 2009 (15 year Levelized, 2011$)

	Annual Capacity Market Values (2011$/kW-yr)		
Zone	**AESC 2009**	**AESC 2011**	**Change**
Maine (ME)	25.15	48.09	91%
Vermont (VT)	25.15	48.09	91%
New Hampshire (NH)	25.15	48.09	91%
Connecticut (statewide)	25.15	48.09	91%
Massachusetts (statewide)	25.15	48.09	91%
Rhode Island (RI)	25.15	48.09	91%
SEMA	25.15	48.09	91%
Central & Western Massachusetts (WCMA)	25.15	48.09	91%
NEMA	25.15	48.09	91%
Rest of Massachusetts (non-NEMA)	25.15	48.09	91%
Norwalk / Stamford (NS)	25.15	48.09	91%
Southwest Connecticut (SWCT) including Norwalk/Stamford	25.15	48.09	91%
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	25.15	48.09	91%
Rest of Connecticut (non-SWCT)	25.15	48.09	91%
Note: Bid into FCM, 15-year levelized (AESC 2009 2010-2024, AESC 2011 2012-2026)			

The AESC 2011 estimates of avoided capacity costs are approximately 91 percent higher than those from AESC 2009 on a 15 year levelized basis. The higher values are primarily due to the extension of the floor price through FCA 6 and the projected need for additional, new, non-RPS related capacity starting in 2020. That need, in turn, is driven by the projected retirements of existing capacity and regulatory changes causing certain existing capacity to be treated as out-of-market ("OOM") resources, and therefore prohibited from setting the market price.[3]

The actual amount of wholesale electric capacity costs avoided by kW reductions from energy efficiency measures will vary according to the approach that the PA responsible for those measures takes towards the FCM. PAs achieve the maximum avoided cost by bidding the entire anticipated kW reduction from measures in a given year into the FCA for that power year. However, PAs have to submit those bids when the FCA is held, which is approximately three years in advance of the applicable power year. PAs also avoid capacity costs from kW reductions that are not bid into FCAs, since those kW reductions lower actual demand, and ISO-NE eventually reflects those lower demands when setting the maximum demand to be met in future FCAs. However, the total amount of avoided capacity costs is lower because of the time lag, up to four years, between the

[3] Out-of-Market resources include capacity from energy efficiency programs that are not allowed to set capacity prices, but are allowed to participate in the capacity market.

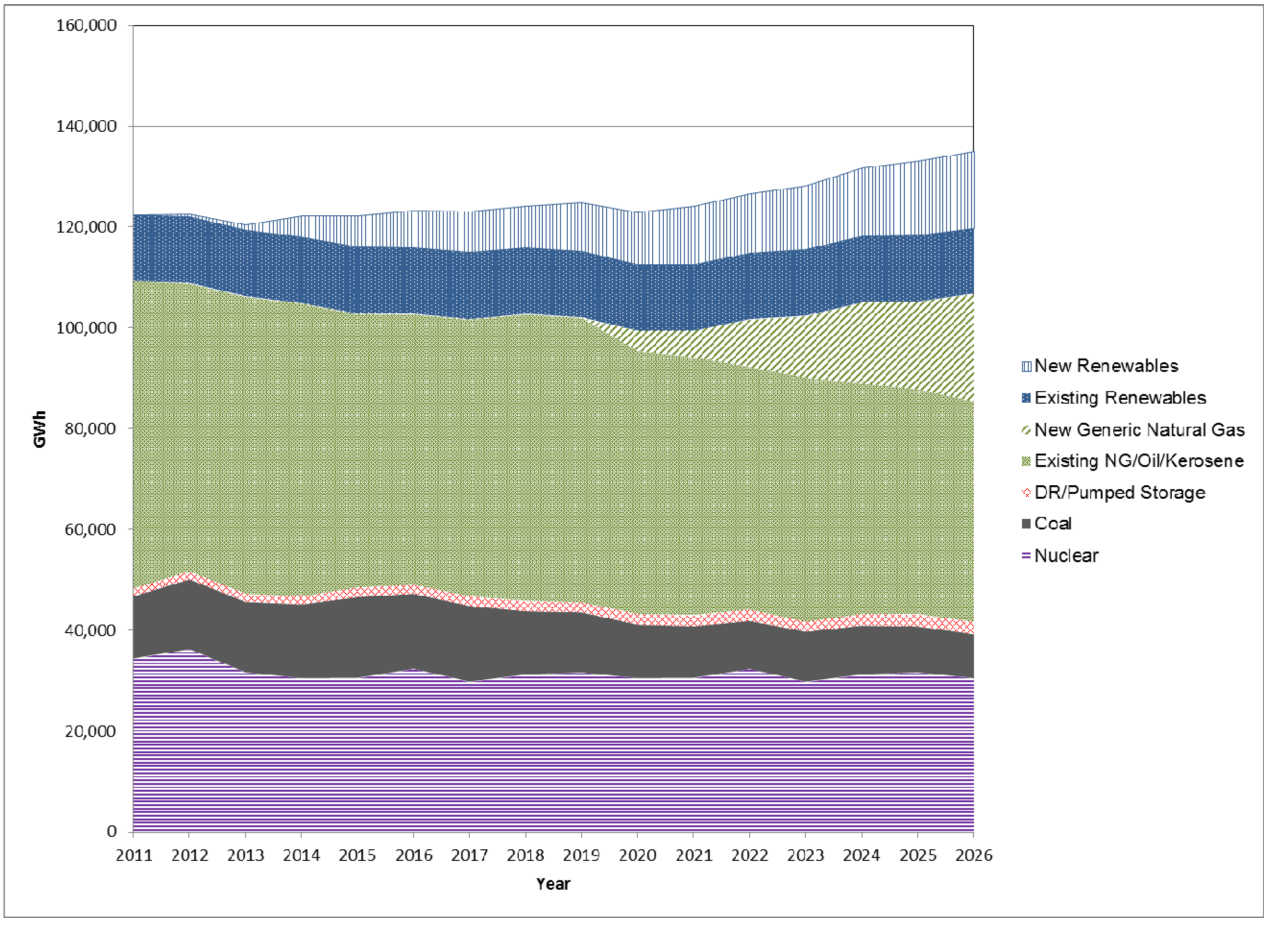
year in which the kW reduction first causes a lower actual peak demand and the year in which ISO-NE translates that kW reduction into a reduction in the total demand for which capacity has to be acquired in a FCA.

1.2.2. Avoided Electric Energy Costs

Avoided electric energy costs are an estimate of the value of a reduction in annual electric energy use by retail customers. The major input to this calculation is the avoided wholesale electric energy cost. To develop an avoided cost at the meter in each state, the avoided wholesale electric energy cost is first increased by the avoided costs of complying with the RPS in that state, and that amount is then increased by the wholesale risk premium mentioned earlier.

Natural gas fired units are the dominant marginal source of generation under the Reference Case, i.e., they set the market price in most hours of most years. The AESC 2011 Reference Case forecast of annual generation by resource type is depicted in Exhibit 1-5.

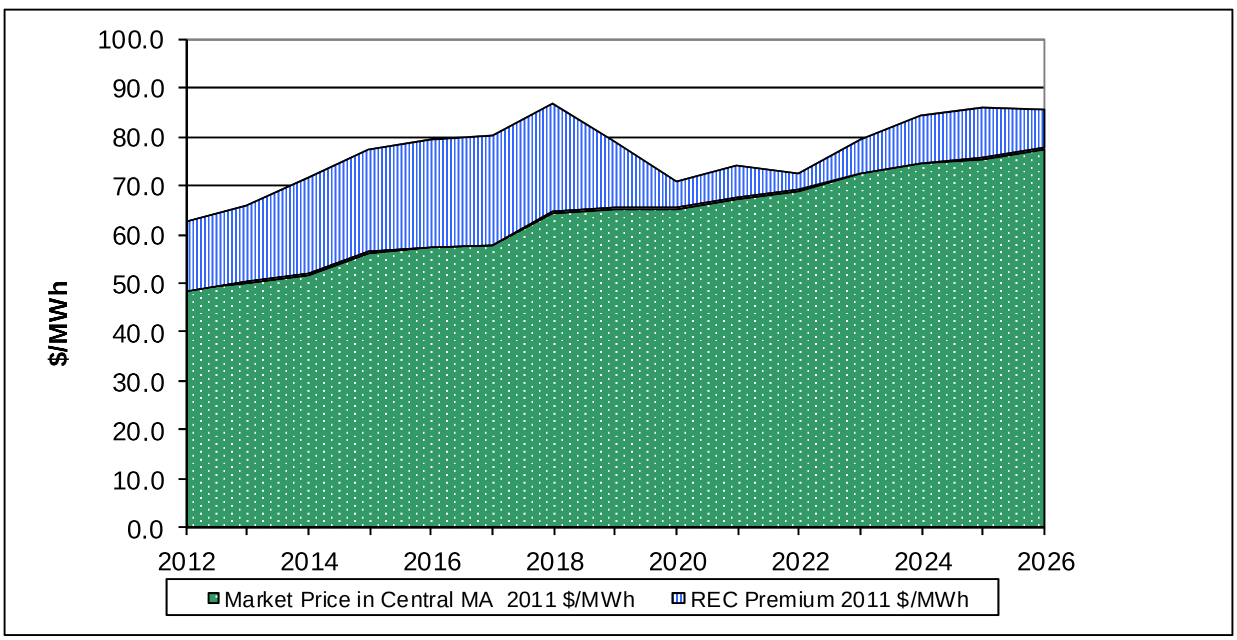
Exhibit 1-5: AESC 2011 Reference Case, Generation by Source (GWh)



The major drivers of avoided electric energy costs are annual load, natural gas prices, and costs to comply with carbon emission regulations. AESC 2011 is projecting levelized annual wholesale electric energy costs to be 15 percent lower than AESC 2009.[4] The majority of the reduction is attributable to the Reference Case projection of wholesale natural gas costs, which is much lower than in AESC 2009. The AESC projection of wholesale natural gas costs is described later in the Executive Summary. The remaining portion of the reduction is due to a change in the assumption of when federal regulation of carbon emissions will start, from 2013 assumed in AESC 2009 to 2018 assumed in AESC 2011.

The avoided costs of RECs are a function of two factors. One factor is the forecast quantity of renewable energy that LSEs will have to acquire in order to comply with the relevant RPS. The second factor is the forecast premium over wholesale electric energy market prices that LSEs will have to pay to acquire that renewable energy. The forecast REC premium is based upon an estimate of REC prices (applicable for each RPS tier), the cost of new entry of Class I renewables from 2019 onward, and the forecast annual wholesale electric energy price. For illustrative purposes for Class 1 RECs, see Exhibit 1-6.

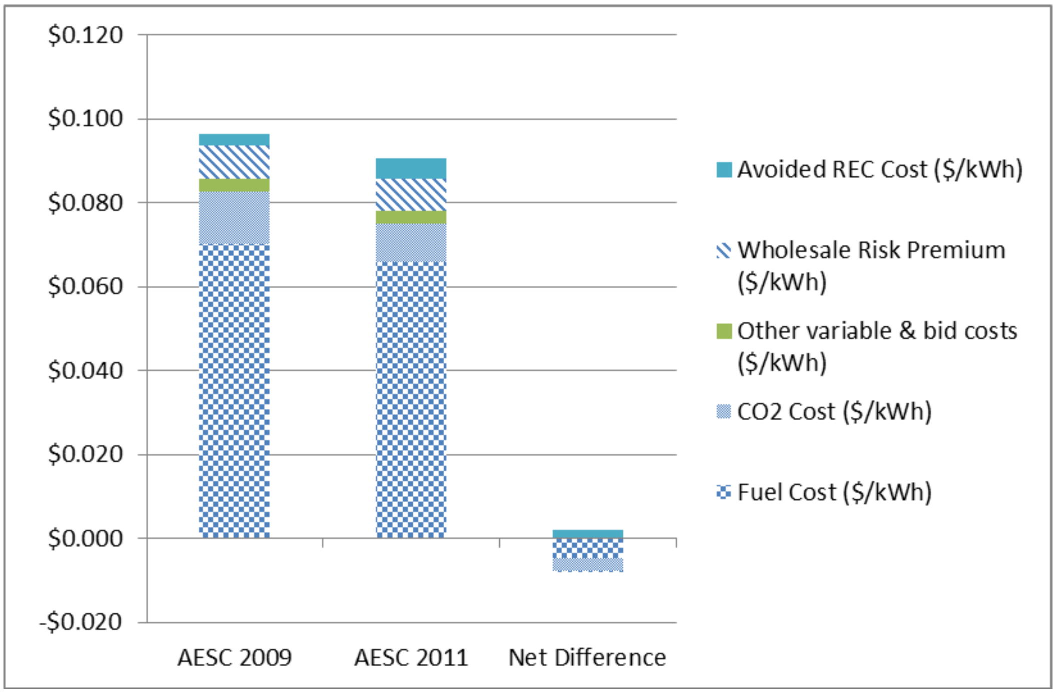
Exhibit 1-6: AESC 2011 Reference Case, Wholesale Electric Energy Prices and REC Premiums



[4] Levelized (2012-2026) for AESC 2011 and AESC 2009 (2010-2024)

The relative magnitude of each component of avoided electric energy cost is illustrated in Exhibit 1-7, which assumes the same efficiency measure implemented in the summer on-peak period in the WCMA zone that is shown in Exhibit 1-1. This illustration indicates that the levelized 0.5 cent per kWh difference between the AESC 2009 avoided energy cost of 9.6 cents per kWh and the AESC 2011 avoided energy cost of 9.1 cents per kWh is primarily attributable to lower natural gas costs, lower carbon costs, and offset by higher REC costs.

Exhibit 1-7: Illustration of Avoided Electric Energy Cost Composition, AESC 2011 vs. AESC 2009 (WCMA Zone, Summer On-Peak, 15 Year Levelized Results, 2011$)



The 15 year levelized projections of avoided electric energy costs for the AESC 2011 and 2009 studies, by zone, are shown in Exhibit 1-8.[5]

[5] AESC 2011 levelized (2012-2026), AESC 2009 levelized (2010-2024)

Exhibit 1-8: Avoided Electric Energy Costs, AESC 2011 vs. AESC 2009 (15 Year Levelized 2011$)

		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy	Annual Weighted Average
	AESC 2011	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	0.067	0.059	0.072	0.058	0.063
2	Vermont (VT)	0.074	0.064	0.087	0.063	0.071
3	New Hampshire (NH)	0.072	0.064	0.078	0.062	0.068
4	Connecticut (statewide)	0.075	0.065	0.089	0.064	0.072
5	Massachusetts (statewide)	0.077	0.067	0.090	0.066	0.074
6	Rhode Island (RI)	0.065	0.055	0.076	0.055	0.061
7	SEMA	0.076	0.067	0.089	0.066	0.073
8	Central & Western Massachusetts (WCMA)	0.077	0.068	0.091	0.066	0.074
9	NEMA	0.076	0.067	0.090	0.065	0.073
10	Rest of Massachusetts (non-NEMA)	0.077	0.068	0.091	0.066	0.074
11	Norwalk / Stamford (NS)	0.076	0.066	0.090	0.065	0.072
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	0.076	0.066	0.090	0.065	0.072
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.075	0.066	0.090	0.064	0.072
14	Rest of Connecticut (non-SWCT)	0.074	0.064	0.088	0.063	0.071
	AESC 2009	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	0.084	0.072	0.088	0.070	0.078
2	Vermont (VT)	0.091	0.076	0.095	0.073	0.083
3	New Hampshire (NH)	0.089	0.074	0.092	0.072	0.081
4	Connecticut (statewide)	0.097	0.080	0.101	0.077	0.088
5	Massachusetts (statewide)	0.093	0.077	0.097	0.074	0.085
6	Rhode Island (RI)	0.084	0.068	0.086	0.065	0.075
7	SEMA	0.093	0.077	0.096	0.073	0.084
8	Central & Western Massachusetts (WCMA)	0.093	0.077	0.096	0.074	0.085
9	NEMA	0.094	0.077	0.097	0.074	0.085
10	Rest of Massachusetts (non-NEMA)	0.093	0.077	0.096	0.074	0.085
11	Norwalk / Stamford (NS)	0.098	0.081	0.102	0.078	0.089
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	0.098	0.081	0.102	0.078	0.089
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.098	0.081	0.102	0.078	0.089
14	Rest of Connecticut (non-SWCT)	0.096	0.080	0.100	0.076	0.087
	Change from AESC 2009	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	(0.017)	(0.013)	(0.016)	(0.012)	(0.014)
2	Vermont (VT)	(0.017)	(0.012)	(0.008)	(0.010)	(0.013)
3	New Hampshire (NH)	(0.016)	(0.011)	(0.014)	(0.009)	(0.013)
4	Connecticut (statewide)	(0.022)	(0.015)	(0.012)	(0.013)	(0.016)
5	Massachusetts (statewide)	(0.017)	(0.010)	(0.006)	(0.008)	(0.011)
6	Rhode Island (RI)	(0.019)	(0.013)	(0.009)	(0.010)	(0.014)
7	SEMA	(0.017)	(0.010)	(0.007)	(0.007)	(0.011)
8	Central & Western Massachusetts (WCMA)	(0.016)	(0.010)	(0.006)	(0.008)	(0.011)
9	Boston (NEMA)	(0.018)	(0.011)	(0.008)	(0.008)	(0.012)
10	Rest of Massachusetts (non-NEMA)	(0.016)	(0.010)	(0.006)	(0.007)	(0.011)
11	Norwalk / Stamford (NS)	(0.022)	(0.015)	(0.012)	(0.013)	(0.017)
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	(0.022)	(0.015)	(0.012)	(0.013)	(0.017)
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	(0.022)	(0.015)	(0.012)	(0.013)	(0.017)
14	Rest of Connecticut (non-SWCT)	(0.022)	(0.015)	(0.012)	(0.013)	(0.016)
	% Change from AESC 2009	**%**	**%**	**%**	**%**	**%**
1	Maine (ME)	-20.1%	-17.5%	-18.3%	-17.5%	-18.5%
2	Vermont (VT)	-19.2%	-15.3%	-8.3%	-14.2%	-15.2%
3	New Hampshire (NH)	-18.6%	-14.3%	-15.0%	-13.2%	-15.7%
4	Connecticut (statewide)	-22.6%	-18.9%	-11.9%	-17.1%	-18.7%
5	Massachusetts (statewide)	-17.7%	-12.8%	-6.5%	-10.3%	-13.0%
6	Rhode Island (RI)	-22.7%	-19.4%	-10.8%	-15.1%	-18.4%
7	SEMA	-18.3%	-12.7%	-6.9%	-9.7%	-13.2%
8	Central & Western Massachusetts (WCMA)	-16.8%	-12.7%	-5.9%	-10.6%	-12.6%
9	Boston (NEMA)	-18.9%	-13.8%	-8.1%	-11.5%	-14.2%
10	Rest of Massachusetts (non-NEMA)	-17.2%	-12.6%	-5.8%	-10.1%	-12.6%
11	Norwalk / Stamford (NS)	-22.6%	-18.9%	-11.9%	-17.1%	-18.6%
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	-22.6%	-18.9%	-11.9%	-17.1%	-18.6%
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	-22.6%	-18.9%	-11.9%	-17.1%	-18.6%
14	Rest of Connecticut (non-SWCT)	-22.6%	-18.9%	-11.9%	-17.1%	-18.7%

As mentioned earlier, the 15 year levelized AESC 2011 avoided energy costs are approximately 15 percent less than those from AESC 2009 on an annual average basis. The decline in summer peak period costs between AESC 2009 and AESC 2011 is generally less than the annual average because of the higher levels of existing capacity retirements projected in AESC 2011. Those retirements change the supply curve, leading to less-efficient units being on the margin during high load hours, and setting prices, in summer peak periods than in AESC 2009. In contrast, the decline in avoided energy costs in AESC 2011 versus AESC 2009 is generally greater than the annual average in the three remaining periods, because the impacts of lower natural gas prices and lower carbon prices is not offset by less-efficient marginal units.

1.2.3. Demand Reduction Induced Price Effects ("DRIPE")

DRIPE is the reduction in prices in the wholesale energy and capacity markets, relative to those forecast in the Reference Case, resulting from the reduction in need for energy and/or capacity due to efficiency and/or demand response programs (i.e., the latter are programs under which consumers agree to reduce their energy consumption during peak demand periods in exchange for financial or other benefits). Thus DRIPE is a measure of the value of efficiency in terms of the reductions in **wholesale prices** seen by all retail customers in a given period. In contrast, avoided electric energy costs and capacity costs measure the value of efficiency in terms of the reductions in the **quantity** of energy used by retail customers in a given period.

The first step in the development of DRIPE is to estimate the impact a reduction in load will have upon the market price, assuming no other changes occur ("gross DRIPE"). The second step is to estimate the pace at which suppliers participating in that market will respond to that reduction with actions that offset the reduction and eventually cause the market price to move toward the level it would have been under the Reference Case ("net DRIPE"). In other words, responses taken by market participants will eventually offset, or dissipate, the DRIPE impact.

The three charts below illustrate the concept using the calculation of capacity DRIPE for FCA 7 as an example.

- **Exhibit 1-9** presents the supply and demand curve used to estimate the Reference Case market price for FCA 7.
- **Exhibit 1-10** illustrates the gross DRIPE effect, i.e., the reduction in price as the demand curve shifts left due to a 100-MW reduction in demand.
- **Exhibit 1-11** illustrates the net DRIPE effect, i.e., the increase in price as the supply curve shifts left due to actions taken by suppliers in response to the lower price in Exhibit 1-10.

Exhibit 1-9: FCA 7 Supply and Demand Curve for FCA 7

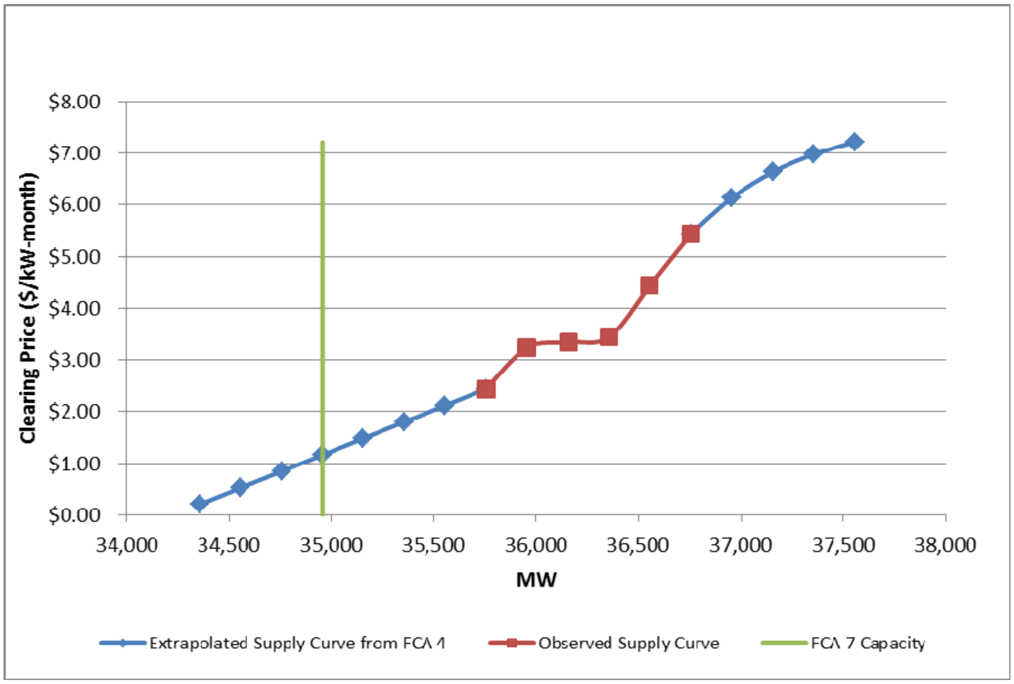


Exhibit 1-10: Gross Capacity DRIPE Response for FCA 7

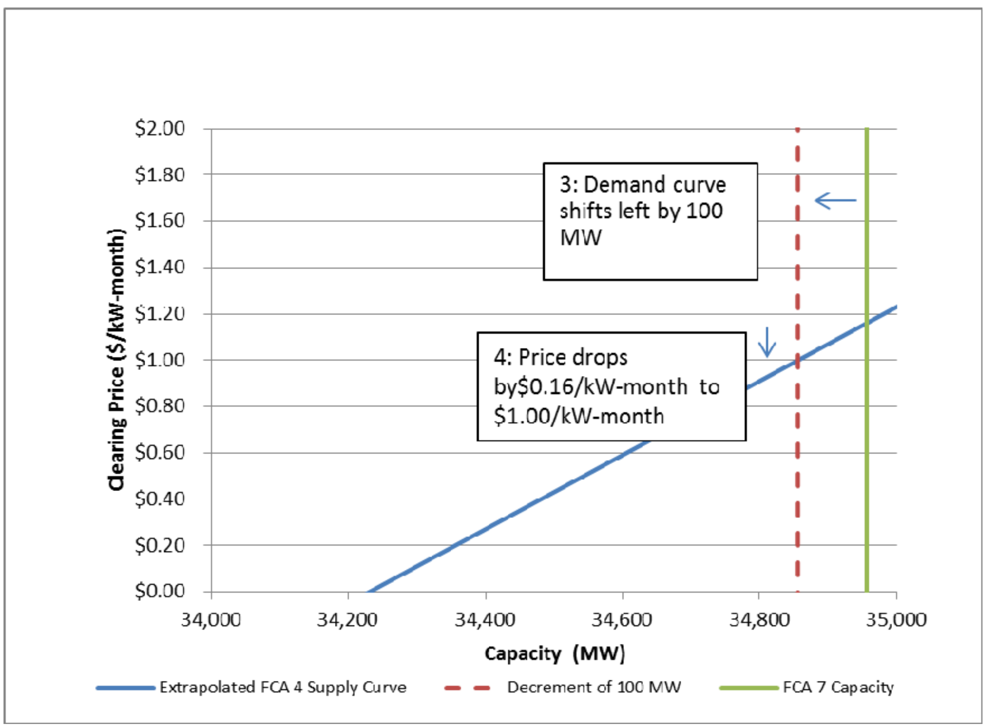
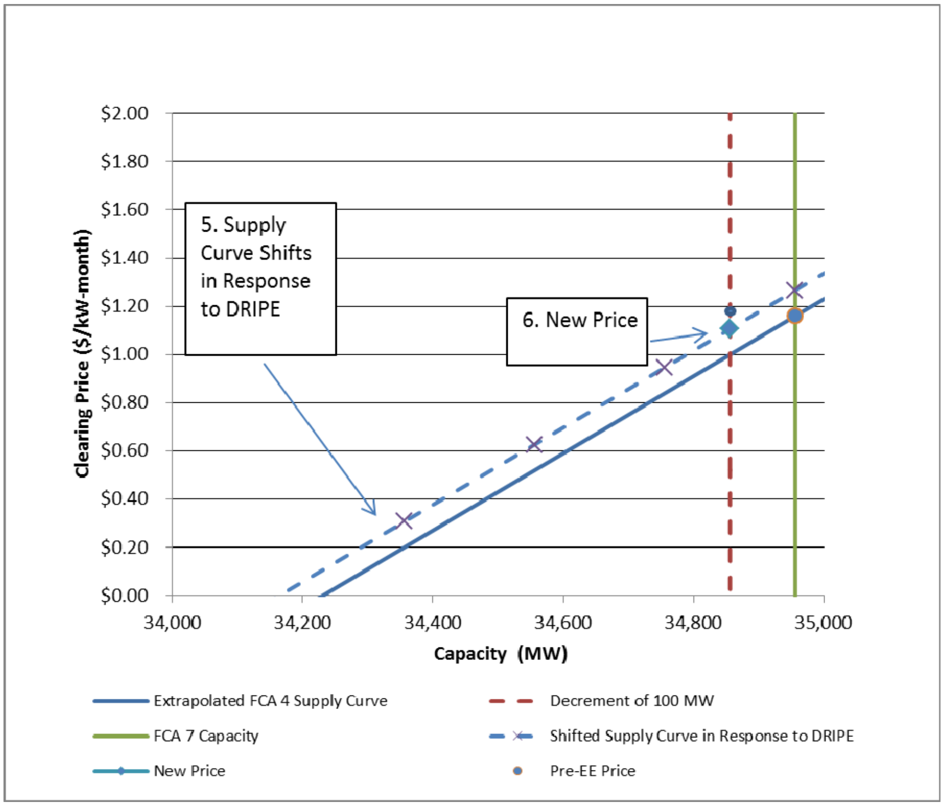


Exhibit 1-11: Net Capacity DRIPE Response for FCA 7



DRIPE impacts are small when expressed as percentage impacts on the market prices of energy and capacity. However, DRIPE impacts are significant when expressed in absolute dollar terms, since very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate to large absolute dollar amounts. DRIPE will have an impact on market prices within the zone where the reduction occurs, referred to as intrastate impacts, as well as throughout the rest of the New England market, referred to as "rest of pool" ("ROP"). Thus DRIPE impacts can be expressed as intrastate only or total (intrastate plus ROP).

Exhibit 1-12 presents 15 year levelized intrastate energy and capacity DRIPE estimates by zone for AESC 2011 and AESC 2009. We recommend that program administrators include DRIPE values in their analyses of demand side management ("DSM"), unless specifically prohibited from doing so by state or local law or regulation.

Exhibit 1-12: Intrastate Energy DRIPE and State Capacity DRIPE for Installations in 2012, AESC 2011 vs. AESC 2009 (15 year Levelized by Zone, 2011$)

	Intrastate Energy DRIPE				State Capacity DRIPE
AESC 2011	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	
Zone	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Maine (ME)	0.005	0.004	0.006	0.005	10.93
Vermont (VT)	0.001	0.001	0.002	0.001	2.23
New Hampshire (NH)	0.004	0.005	0.009	0.005	7.51
Connecticut (statewide)	0.014	0.014	0.028	0.019	30.72
Massachusetts (statewide)	0.018	0.017	0.032	0.018	59.07
Rhode Island (RI)	0.006	0.005	0.007	0.004	9.48
SEMA	0.018	0.017	0.032	0.018	59.07
Central & Western Massachusetts (WCMA)	0.018	0.017	0.032	0.018	59.07
NEMA	0.018	0.017	0.032	0.018	59.07
Rest of Massachusetts (non-NEMA)	0.018	0.017	0.032	0.018	59.07
Norwalk / Stamford (NS)	0.014	0.014	0.028	0.019	30.72
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.014	0.014	0.028	0.019	30.72
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.014	0.014	0.028	0.019	30.72
Rest of Conneticut	0.014	0.014	0.028	0.019	30.72

AESC 2009	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Maine (ME)	0.005	0.003	0.004	0.003	2.19
Vermont (VT)	0.001	0.000	0.001	0.001	0.71
New Hampshire (NH)	0.002	0.002	0.003	0.001	1.18
Connecticut (statewide)	0.019	0.012	0.020	0.009	6.57
Massachusetts (statewide)	0.025	0.020	0.027	0.014	12.54
Rhode Island (RI)	0.006	0.006	0.003	0.002	1.99
SEMA	0.025	0.020	0.027	0.014	12.54
Central & Western Massachusetts (WCMA)	0.025	0.020	0.027	0.014	12.54
Boston (NEMA)	0.025	0.020	0.027	0.014	12.54
Rest of Massachusetts (non-NEMA)	0.025	0.020	0.027	0.014	12.54
Norwalk / Stamford (NS)	0.019	0.012	0.020	0.009	6.57
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.019	0.012	0.020	0.009	6.57
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.019	0.012	0.020	0.009	6.57
Rest of Connecticut (non-SWCT)	0.019	0.012	0.020	0.009	6.57

On a 15 year levelized basis, the 2011 AESC estimates of capacity DRIPE are approximately four times greater than those from AESC 2009.[6] This increase is primarily due to the projection of higher wholesale capacity prices than in AESC 2009, as well as to the projection of a longer phase-out of capacity DRIPE effects than in AESC 2009. The AESC 2011 projections assume the phase-out, or dissipation, of capacity DRIPE will last up to 11 years, versus four years assumed in AESC 2009. The longer projected dissipation of capacity DRIPE is based upon an analysis of the various factors that tend to offset the reduction in capacity prices. Those factors include timing of new capacity additions, timing of retirements of existing capacity, elasticity of customer demand, and the portion of capacity that LSEs acquire from the FCM.

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[6] AESC 2009 values for 2010 Installations levelized from 2010-2024.

The AESC 2011 estimates of intrastate energy DRIPE are approximately 22 percent higher on a simple average basis than those from AESC 2009. These higher estimates are primarily due to a longer delay, compared to AESC 2009, before new generation is assumed to begin offsetting gross energy DRIPE.

The projected duration of energy DRIPE and capacity DRIPE in three studies reviewed in detail for AESC 2011 ranges from 7 to 12 years.[7] The AESC 2011 projection of a 13-year phase-out for energy DRIPE and an 11-year phase-out for capacity DRIPE are within the range of dissipation values presented in other studies.[8]

Although uncertainty remains regarding the projections of energy DRIPE and capacity DRIPE, the consensus among the Study Group members and the Project Team is that these projections are comprehensive and reasonable based on the available information.

1.2.4. Carbon-Dioxide Externalities

Externalities are impacts from the production of a good or service that are neither reflected in the price of that good or service nor considered in the decision to provide that good or service. There are many externalities associated with the production of electricity, including the adverse impacts of emissions of SO_2, mercury, particulates, NO_x, and CO_2. However, the magnitude of most of those externalities has been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of their adverse impacts in their production and use decisions. In other words, a portion of the costs of the adverse impact of most of these externalities has already been "internalized" in the price of electricity.

AESC 2011 identifies the impacts of carbon dioxide as the dominant externality associated with marginal electricity generation in New England over the study period, for two main reasons. First, policy makers are just starting to develop and implement regulations that will "internalize" the costs associated with the impacts of carbon dioxide from electricity production and other energy uses. Under the Regional Greenhouse Gas Initiative ("RGGI") a portion of the long-term marginal abatement cost (LTMAC) of carbon is "internalized" in wholesale electric energy prices. AESC 2011 assumes that, by 2018, new federal CO_2 regulations will increase the portion of the LTMAC of carbon that is internalized in those wholesale market prices. However, even with those current and projected regulations, AESC 2011 projects a significant externality value for CO_2. Second, New England avoided electric energy costs over the study period are likely to be

[7] These studies are summarized in Exhibit 6-43.

[8] DRIPE durations described for 2012 installations. For 2013 installations, the energy DRIPE duration is 12 years and the capacity DRIPE duration is 13 years.

dominated by natural gas-fired generation, which has minimal emissions of SO_2, mercury, particulates and NO_x, but substantial emissions of CO_2.

The AESC 2011 estimate of the LTMAC of carbon, at $80 per ton, is essentially the same as the AESC 2009 estimate. It is based on the same approach as AESC 2009, wherein we estimate the cost of limiting CO_2 emissions to a "sustainability target" level. The AESC 2011 estimate reflects the most recent literature on the cost of achieving this level.

AESC 2011 estimates of 15 year levelized CO_2 externality costs by zone are presented in Exhibit 1-13 below.[9] The AESC 2011 estimates of CO_2 externalities per kWh are approximately 16 percent higher than those from AESC 2009 on a 15 year levelized basis. These unit values are higher because AESC 2011 internalizes a smaller portion of the LTMAC of carbon in market prices.

Exhibit 1-13: Avoided CO_2 Externality Costs by Zone, 15 year Levelized ($/kWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
AESC 2011	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
Maine (ME)	0.035	0.036	0.034	0.037
Vermont (VT)	0.035	0.036	0.034	0.037
New Hampshire (NH)	0.035	0.036	0.034	0.037
Connecticut (statewide)	0.035	0.036	0.034	0.037
Massachusetts (statewide)	0.035	0.036	0.034	0.037
Rhode Island (RI)	0.042	0.043	0.041	0.045
SEMA	0.035	0.036	0.034	0.037
Central & Western Massachusetts (WCMA)	0.035	0.036	0.034	0.037
NEMA	0.035	0.036	0.034	0.037
Rest of Massachusetts (non-NEMA)	0.035	0.036	0.034	0.037
Norwalk / Stamford (NS)	0.035	0.036	0.034	0.037
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.035	0.036	0.034	0.037
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.035	0.036	0.034	0.037
Rest of Connecticut (non-SWCT)	0.035	0.036	0.034	0.037

Efficiency measures can lead to reductions in the absolute quantity of CO_2 emissions primarily by demonstrating that existing caps can be met at less cost than anticipated, and thus justifying new, tighter caps. As with DRIPE, we recommend that program administrators include CO_2 additional environmental costs in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation.

[9] Values for Rhode Island incorporate RGGI only scenario.

1.3. Avoided Costs of Natural Gas

Gas efficiency programs, like electric energy efficiency programs, have a number of key energy cost benefits. The benefits from those reductions include some or all of the following avoided costs:

- Avoided gas supply costs due to a reduction in the annual quantity of gas that has to be produced, transported by pipeline, and stored to meet winter heating requirements;
- Avoided gas costs of local distribution infrastructure due to a reduction in the timing and/or size of new projects that have to be built resulting from the reduction in gas that has to be delivered; and
- Avoided environmental externalities due to a reduction in the quantity of gas that is burned.

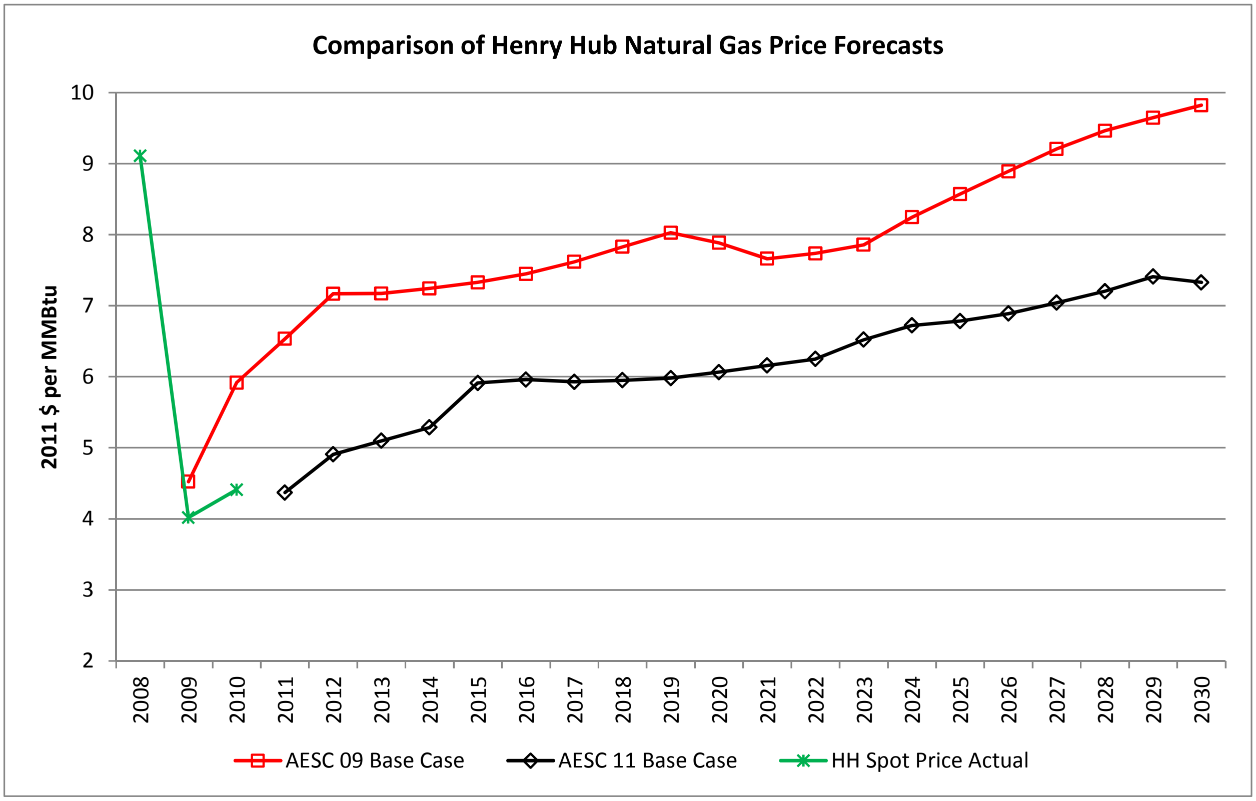
1.3.1. Projected Henry Hub Prices

The largest component of avoided gas supply costs is the cost of buying gas. In developing the Reference Case for AESC 2011, we use the price of gas at the Henry Hub in Louisiana as a proxy for that cost. The forecast is based upon the New York Mercantile Exchange ("NYMEX") gas futures prices for the Henry Hub for the years 2011 to 2014 and the "High Shale Gas" Case forecast from the Energy Information Administration's ("EIA") 2010 Annual Energy Outlook ("AEO 2010") for the years 2015 onward.

We drew upon the AEO 2010 High Shale Gas Case because its forecast prices are consistent with our estimate of the full-cycle, all-in cost of finding, developing, and producing gas from shale resources, and because it assumes unproved shale gas resources comparable in size to the Reference Case presented in the AEO 2011. In contrast, the long-run marginal cost of shale gas implicit in the AEO 2011 Reference Case is significantly less than our estimate of the full-cycle, all-in cost of finding, developing, and producing shale gas.

The AESC 2011 Reference Case forecast is presented in Exhibit 1-14.

Exhibit 1-14: Comparison of Henry Hub Gas Price Forecasts, AESC 2011 vs. AESC 2009 (2011$ $/MMBtu)

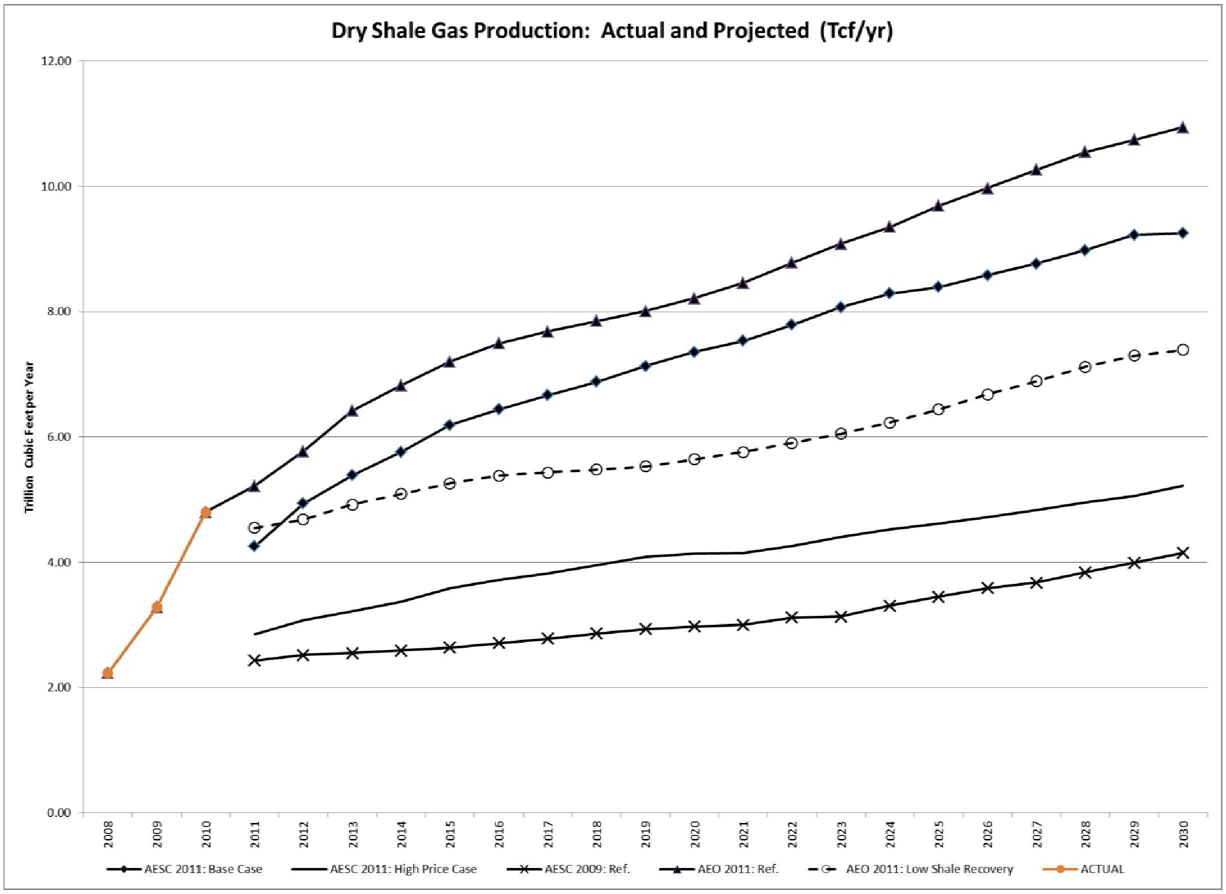


The AESC 2011 price forecast is lower than the AESC 2009 forecast due to the significant changes in expectations regarding the cost of finding, developing, and producing gas from shale gas resources, and the quantity of shale gas production. Our AESC 2011 forecast, based on a more detailed analysis of published data from seven major shale gas producers, indicates a lower full-cycle cost of shale gas, one equating to a Henry Hub price of $5.50 per MMBtu.[10]

As indicated in Exhibit 1-15, the AEO 2011 Reference Case assumes a shale gas production of 9.69 Tcf in 2025. The AESC 2011 Reference Case forecast is consistent with a somewhat lower level of shale gas development and production; for example, it assumes shale gas production of 8.39 Tcf in 2025, about 13 percent lower than the AEO 2011 Reference Case. The AESC 2011 High Gas Price Case assumes an even lower level of production.

[10] The AESC 2009 forecast was based on our estimate that the full-cycle cost of producing shale gas equated to a Henry Hub price ranging between $6.50 per MMBtu and $8.00 per MMBtu

Exhibit 1-15: Shale Gas Production, Actual and Projected (Tcf/year)



There is considerable uncertainty regarding projections of shale gas production quantities and costs. First, AEO 2011 has identified several uncertainties that could result in less production or higher costs. Since AEO 2011 projections are based upon limited experience with many shale gas formations, the projections may overestimate the quantity of shale gas production or underestimate the future cost of shale gas production. Alternatively, technical advances may reduce production costs and currently untested shale gas formations could prove to be highly productive. Second, concerns have been raised regarding the need for additional regulation of hydraulic fracturing in order to minimize its environmental impacts on groundwater, surface water, and air emissions. However, during the preparation of this Study we did not find any public projections of specific changes in existing Federal, state and local regulations, including scope and timing, from which to credibly estimate the impact on the cost of shale gas production.[11]

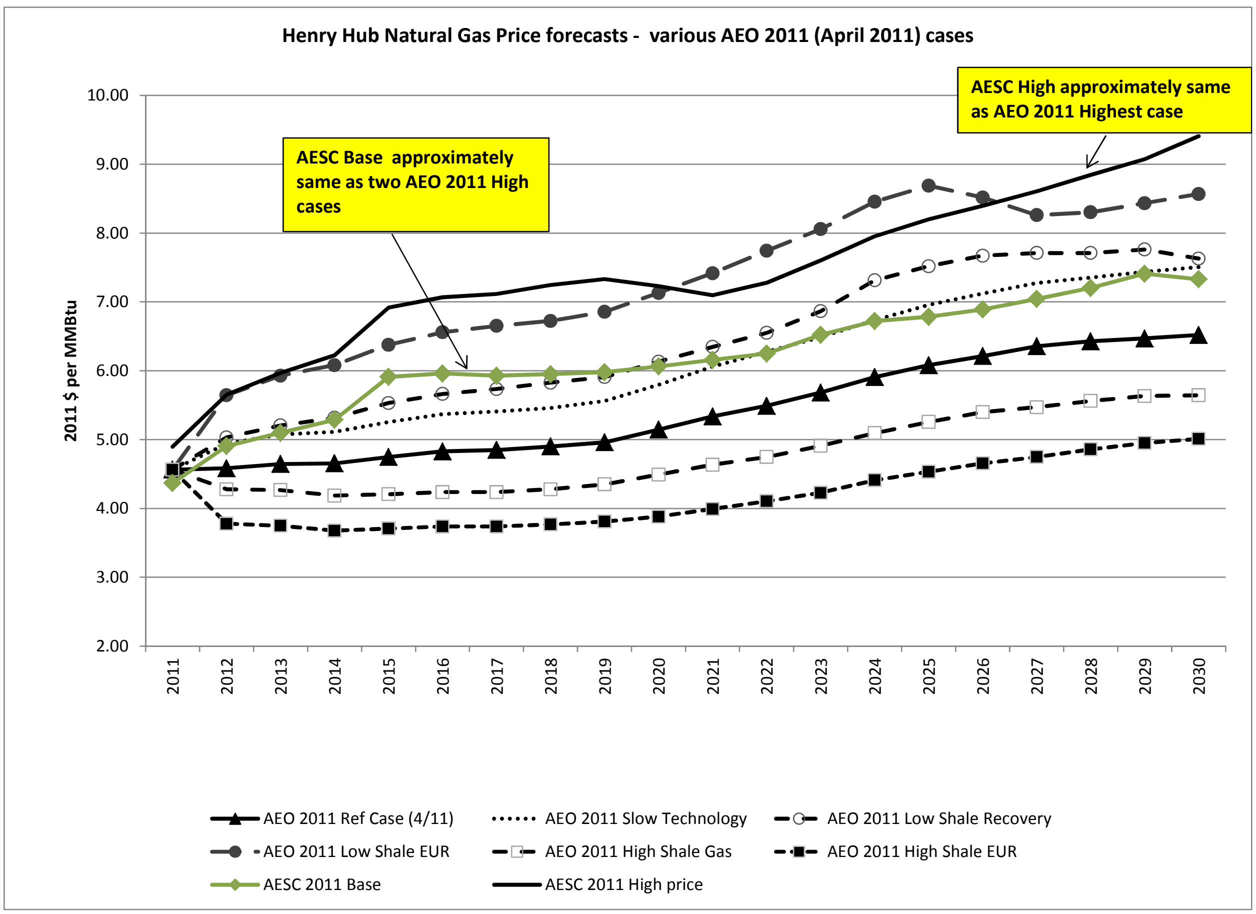
[11] Unlike expectations regarding future Federal regulation of CO_2 emissions, there are not dozens of projections available for parties to analyze and upon which parties can make an informed judgment.

We do expect that companies will be required to disclose the chemicals they use in their fracturing fluids, but that such disclosures will not have a material impact on shale gas production quantities or cost.

The AESC 2011 High Gas Price Case provides a projection that reflects the uncertainty regarding projections of quantities and costs related to shale gas production. The High Gas Price Case projects gas prices for a scenario in which the development of shale gas is restricted to approximately 50 percent of Reference Case levels with correspondingly higher development costs.

As indicated in Exhibit 1-16, the AESC 2011 Reference Case forecast of prices is comparable to two of the high gas price cases from AEO 2011. The AESC 2011 High Case gas prices are comparable to gas prices in the highest AEO 2011 gas price case.

Exhibit 1-16: Comparison of Henry Hub Gas Price Forecasts, AESC 2011 vs. AEO 2011 ($/MMBtu)



Given the uncertainty associated with projections of shale gas resource availability, production quantities, regulations, and costs, there is certainly a possibility that material changes in the long-term outlook for shale gas production and cost may occur after the completion of AESC 2011 and before the initiation of AESC 2013. Those material changes might be driven by public developments such as significant revisions to public geological analyses; a legislative body, policy agency, or regulatory agency identifying specific changes in the regulation of hydraulic fracturing; published estimates of the costs associated with regulatory changes; or changes in natural gas market prices. In the event of such public developments, members of the Study Group may choose to determine if the AESC 2011 Reference Case and High Gas Price Case projections of natural gas prices are still suitable for use in energy efficiency cost-effectiveness analyses. If they determine that neither of those projections is within a range of reasonableness in light of the public developments, the members of the Study Group should consider revising the natural gas price forecast and the avoided costs.

1.3.2. Projected Avoided City-Gate and Retail Gas Costs

AESC 2011 provides estimates of each category of avoided costs for three regions. These are Connecticut and Rhode Island ("southern New England"), Massachusetts, Maine, and New Hampshire ("central and northern New England") and Vermont. For each region the estimates are presented by year and by major end-use. These estimates of avoided gas costs reflect all fixed and variable costs that would be avoided due to a reduction in gas use. Unlike the electric industry, which has an FCM separate from the energy market, there is no separate avoided gas capacity cost beyond, or additional to, the estimated avoided gas supply costs.

The AESC 2011 projections of avoided natural gas costs to retail customers over the next 15 years range from $10.00 to $12.00 per dekatherm ("DT") (2011$) depending on the end-use and location, as shown in Exhibit 1-17.

Exhibit 1-17: Comparison of Avoided Gas Costs by End-Use Assuming Some Avoidable Retail Margin, AESC 2011 vs. AESC 2009 (15 year Levelized, 2011$/DT)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
2009 to 2011 change	-34.33%	-34.33%	-36.54%	-33.82%	-24.71%	-26.84%	-26.08%	-29.92%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
2009 to 2011 change	-32.57%	-32.57%	-35.03%	-32.38%	-25.64%	-28.37%	-27.41%	-29.99%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
2009 to 2011 change	-23.86%	-23.86%	-21.95%	-20.36%	-10.57%	-5.67%	-6.82%	-12.44%

(a) Factor to convert 2009$ to 2011 $ 1.0186

Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discount rate of 2.465%.

AESC 2011 is projecting avoided costs for each end-use that are 25 percent to 35 percent lower than AESC 2009. The lower avoided costs are due to the forecast of lower Henry Hub natural gas prices and lower avoided distribution costs. The lower forecast of avoided distribution costs is based upon the results of the most recent estimates of marginal costs prepared by several of the gas utility members of the AESC Study Group.

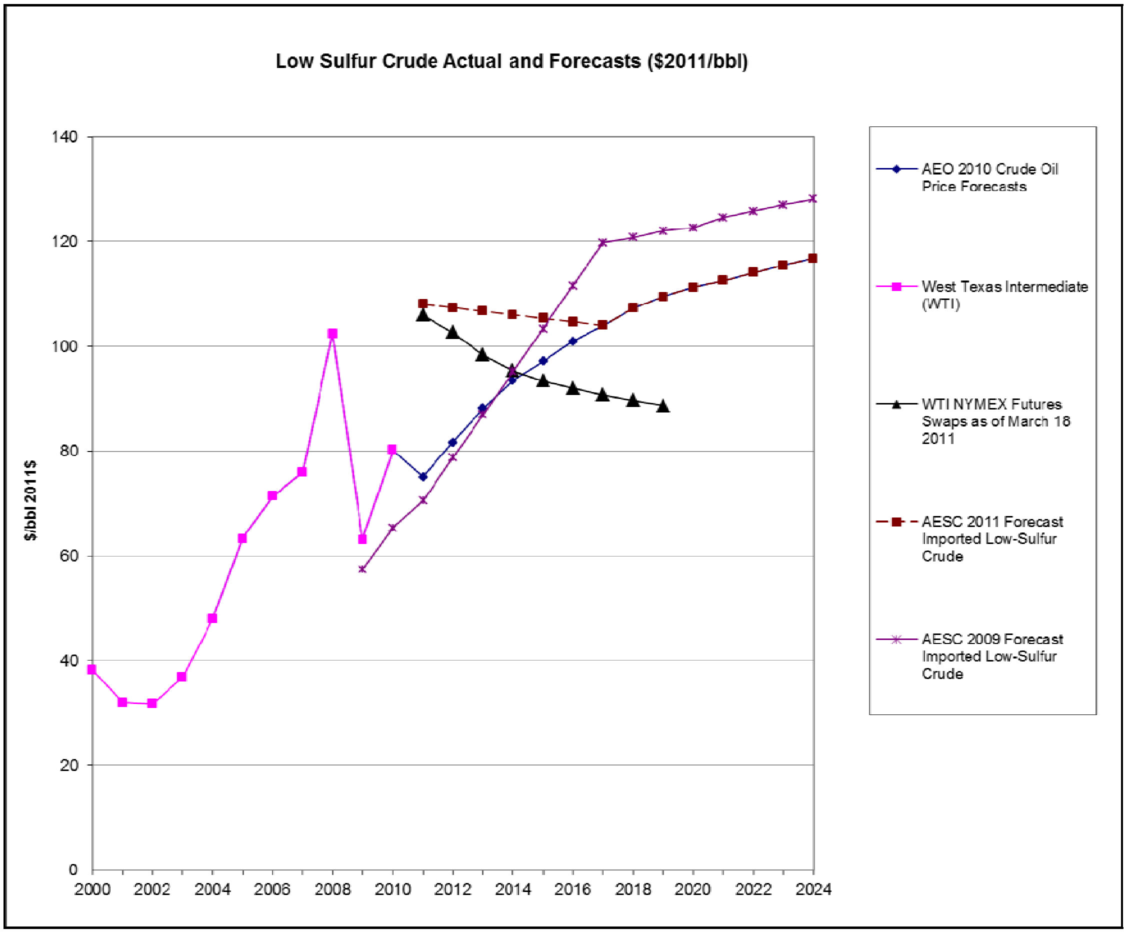
1.4. Avoided Costs of Other Fuels

Some electric and gas efficiency programs enable retail customers to reduce their use of energy sources other than electricity or natural gas. The benefits from reducing the use of other fuels include avoided fuel supply costs and avoided environmental externalities.

The major driver of these avoided fuel costs are forecast crude oil costs. Given the significant uncertainty regarding the future price of crude oil, the AESC 2011 forecast of crude oil prices is based upon the EIA's Short-Term Energy Outlook ("STEO") of March 2010 for 2011 and 2012, NYMEX prices for 2013 as of March 18, 2011, and then AEO 2010 Reference Case forecast prices from 2014 onward. This forecast is higher than the AESC 2009 forecast in the years prior to 2015 and lower thereafter.

The AESC 2011 and AESC 2009 forecasts of crude oil are presented in Exhibit 1-18.

Exhibit 1-18: Low-Sulfur Crude Oil Actual and Forecast (2011$ per bbl)



The AESC 2011 forecasts of avoided costs of fuels by sector and region are summarized in Exhibit 1-19.

Exhibit 1-19: Comparison of Avoided Costs of Other Retail Fuels (15 year Levelized, 2011$)

	No. 2 Distillate	**No. 2 Distillate**	**No. 6 Residual (low Sulfur)**	**Propane**	**Kerosene**	**BioFuel**	**BioFuel**	**Wood**
Sector	**Res**	**Com**	**Com**	**Res**	**Res & Com**	**B5 Blend**	**B20 Blend**	**Res**
AESC 2011 Levelized Values (2011$/MMBtu)								
2012-2026	25.37	23.53	17.26	36.00	25.50	25.37	25.37	9.47
AESC 2009 Levelized Values (2011$/MMBtu)								
2010-2024	23.25	22.09	17.85	34.66	22.59	23.25	23.25	8.38
Percent Difference from AESC 2009								
	9.1%	6.5%	-3.3%	3.9%	12.9%	9.1%	9.1%	13.0%

Notes
Res = Residential Sector
Com = Commercial Sector

The AESC 2011 avoided costs for these fuel prices are generally higher than those from AESC 2009 primarily due to a higher forecast of underlying crude oil prices. On a 15 year levelized basis, the AESC 2011 values are higher by six to 13 percent depending on the fuel and sector. The values reported for wood are for cordwood. Values for wood pellets would be approximately twice as high according to the limited available data on wood pellet prices.

Chapter 2: Methodology & Assumptions Underlying Projections of Avoided Electricity Supply Costs

2.1. Background

One goal of the AESC study is to project the electricity supply costs that would be avoided by reductions in retail energy and/or demand through energy efficiency initiatives. The avoided electricity supply costs incorporate: avoided electric energy market prices, avoided capacity market prices, avoidable costs not internalized in those market prices, and demand reduction induced price effects (DRIPE). The developed avoided electricity supply costs are presented in Chapter 6. This Chapter describes the methodology and assumptions used to develop those avoided electricity supply costs.

For AESC 2011, we use Market Analytics, under license from Ventyx, to estimate electric energy market prices by simulating the operation of the wholesale electric-energy market. We use a spreadsheet model to estimate electric capacity market prices by simulating future Forward Capacity Auctions in the forward capacity market. Section 2.2 describes the general common assumptions used in both models. Sections 2.3 and 2.4 describe the methodologies used to develop electric energy market prices and electric capacity market prices respectively, as well as the specific values of the assumptions used as inputs to each model. Section 2.5 describes the methodology and assumptions we use to develop a forecast of the components of avoided electricity supply costs that are not internalized in the wholesale market prices for energy and capacity, as well as estimates of DRIPE.

Chapter 6 details the avoided electricity supply costs for the New England region as a whole as well as for each of 14 component zones in each year of the planning horizon (2011–2041). Each set of avoided electricity supply costs comprises avoided energy costs by year for the four energy costing periods: Summer On-Peak, Summer Off-Peak, Winter On-Peak, and Winter Off-Peak.

For all zones, Summer On-peak is as defined by ISO-New England (ISO-NE), June-September, weekdays 7 am to 11 pm; Off-peak is 11 pm to 7 am weekdays, plus weekends, and holidays. Winter period is the remaining eight months with the same diurnal time divisions, weekends and holidays.

2.2. Wholesale Market Prices for Electric Energy and Capacity: Common Methodologies & Assumptions

2.2.1. Structure of Wholesale Markets

The ISO-NE market is part of the Northeast Power Coordinating Council and includes the six states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and

Vermont.[12] ISO-New England is the regional transmission organization (RTO) for the New England power market. It coordinates several markets for electric-power products including energy, capacity, and operating reserves markets (regulation up and down, spinning reserves, ten-minute non-spinning reserves, and thirty-minute non-spinning reserves).

The modeling and reporting zones are discussed in section 2.3.2.1

2.2.1.1. Wholesale Energy Markets

The wholesale energy markets are managed by ISO-NE. There are two primary markets: (1) the Day-Ahead Market where the majority of the transactions occur and (2) the Real-Time Market where the remaining energy supplies and demands are balanced. These two markets represent the bulk of the electricity transactions and their prices on average are very close to each other, although there is greater volatility in the real-time market.

According to ISO-New England (2010, 28–30):

> Locational marginal pricing is a way for wholesale electric energy prices to efficiently reflect the value of electric energy at different locations based on the patterns of load, generation, and the physical limits of the transmission system. Wholesale electricity prices are identified at 900 pricing points (i.e., *pnodes*) on the bulk power grid. LMPs differ among these locations because transmission and reserve constraints prevent the next-cheapest megawatt (MW) of electric energy from reaching all locations of the grid. Even during periods when the cheapest megawatt can reach all locations, the marginal cost of physical losses will result in different LMPs across the system.
>
> If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment of load. This incremental megawatt of load would be served by the generator with the lowest-cost energy offer that is available to serve that load, and electric energy from that generator would be able to flow to any node over the transmission system.
>
> New England has five types of pnodes: one type is an external proxy node interface with neighboring *balancing authority areas*, and four types are internal to the New England system.[57] The internal pnodes include individual generator-unit nodes, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub. The *Hub* is a collection of locations with a load-weighted price intended to represent an uncongested price for electric energy; facilitate trading; and enhance transparency and liquidity in the marketplace. New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).Generators are paid the real-time LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones. The load-zone price is a load-weighted average price of the load-node prices in that zone.

[12] Parts of northeastern Maine are not included in ISO-New England.

The intersection of the supply and demand curves as offered and bid, along with transmission constraints and other system conditions, determines the Day-Ahead Energy Market price at each node and results in the binding financial schedules and commitment orders (refer to Figure 2-1). Market participants that have *real-time load obligations* (RTLOs) (i.e., they are serving load) may submit demand bids in the Day-Ahead Energy Market. Participants may bid *fixed demand* (i.e., they will buy at any price) and *price-sensitive demand* (i.e., they will buy up to a certain price) at their load zone (or pnode, for some participants that meet certain requirements). Generating units may submit three-part supply offers for their output at the pricing node specific to their location, including start-up, no-load, and incremental energy offers. Start-up offers reflect the costs associated with bringing a unit from an off-line state to the point of synchronizing with the grid. No-load offers reflect the hourly cost of operating that does not depend on the megawatt level of output. Incremental energy offers represent the willingness of participants to operate a resource at higher output levels for higher compensation. The incremental energy offers produce the upward sloping supply curve that is used to calculate the LMP. Market participants have the incentive to submit offers for start-up, no-load, and incremental energy consistent with their true costs to maximize the chance they will be running at profitable levels.

Any participant that satisfies the financial-assurance requirements detailed in the market rules also may bid price-sensitive *virtual demand* at any pricing node on the system in the Day-Ahead Energy Market. Participants also may offer *virtual supply*. Virtual trading enables market participants that are not generator owners or load-serving entities (LSEs) to participate in the Day-Ahead Energy Market by establishing virtual (or financial) positions. It also allows more participation in the day-ahead price-setting process, allows participants to manage risk in a multi-settlement environment, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets.

Demand bids and virtual demand bids both can be used to hedge the difference between day-ahead and real-time prices. Demand bids are well suited to hedge RTLOs, and virtual demand bids can be used to arbitrage expected differences between day-ahead and real-time prices at a node or to hedge a nodal load.

For each megawatt of virtual supply that clears in the Day-Ahead Energy Market, the participant receives the day-ahead LMP and has a financial obligation to pay the real-time LMP at the same location. For each megawatt of cleared virtual demand, the participant pays the day-ahead LMP and receives the real-time LMP at that location. That is, an accepted virtual supply offer in the Day-Ahead Energy Market is offset by a “purchase” in the Real-Time Energy Market, and a cleared virtual demand bid in the Day-Ahead Energy Market is offset by a “sale” in the Real-Time Energy Market. While these transactions affect the day-ahead prices, they do not represent physical supply or withdrawal of energy in real time. The financial outcome for a particular participant is determined by the difference between the day-ahead and real-time LMPs at the location at which the participant‘s offer or bid clears, plus all applicable transaction costs, including daily reliability costs (refer to Section 2.5).

Real-Time Market Supply and Demand and Generator Commitment

The Real-Time Energy Market is a physical delivery market rather than a financial forward market like the Day-Ahead Energy Market. The Real-Time Energy Market is the environment in which the ISO control room commits and dispatches physical resources to meet actual real-time load, including the minute-to-minute balancing of energy and reserves while accounting for transmission system limits and the need to provide contingency coverage. While the financial schedules produced by the Day-Ahead Energy Market clearing process provide a starting point for the operation of the Real-Time Energy Market, the amount of needed and available supply at each location can increase or decrease for a number of reasons. First, all generators have the flexibility to revise their incremental energy supply offers during the *reoffer period*. In addition, generating-unit and transmission line outages, along with unexpected changes in demand, can cause the ISO to call on additional generating resources to preserve the balance of supply and demand.

2.2.1.2. Wholesale Capacity Market

The capacity markets previously operated by ISO-NE were superseded in June 2010 by the Forward Capacity Market (FCM). The power year for the FCM, also referred to as an FCM year is from June through May. Thus, for a calendar year the unit cost (expressed as dollars per kW-year) of capacity in the FCM, will be the average of January through May from one power year and June through December of the following power year.

Under the FCM, ISO-NE acquires sufficient capacity to satisfy the installed capacity requirement (ICR) it has set for a given power-year through a forward-capacity auction (FCA) for that power-year.[13] The price for capacity in that power year is based upon the results of the FCA for that year. The FCA for each power year is conducted roughly three years in advance of the start of that year. ISO-NE has held four FCAs to date, FCA 1 for the power year starting June 2010 held in 2008 through FCA 4 for the power year starting June 2013 which was held in 2010.

Under current FCM rules, each FCA will have a ceiling price and a floor price through FCA 6. The original FCA rules provided for floor prices only through FCA 3, however the ISO and FERC have extended the floor prices through FCA 6. The status of floor prices for auctions after FCA 6 is at this time uncertain. For the first four FCAs, the floors were $4.50, $3.60, $2.95, and $2.95/kW-month respectively. Each of these auctions concluded when it reached the floor price, although the amount of capacity

[13] Some of the ICR (1,400 MW in the first FCA, and 911–916 MW in the second through fourth FCA) was met by installed capacity credits from the Phase I/II interconnection, which are allocated to the transmission owners with entitlements in the line. The Hydro Quebec Interconnect Certificate rights are valued at the market-clearing price, and the actual auction acquires the remaining ICR, called the net ICR or NICR.

offered at that price still exceeded the requirement. [14] The floor price for FCA 5 was set at, and cleared at, \$3.21/kW-month.[15] The floor price for FCA 6 will rise from the FCA 5 floor price by an escalation factor set by the Handy-Whitman Index of Public Utility Costs.

Suppliers of capacity whose bids are accepted in the FCA are paid an amount equal to the quantity of capacity they bid multiplied by the final auction price (prorated as described in footnote 14). In each month of the capacity year, this amount is reduced by *peak energy rents,* (PER), an estimate by ISO-NE of the annual wholesale energy market revenues that of a hypothetical generator with a heat rate of 22,000 Btu/kWh would earn[16]. Suppliers are also subject to penalties for any failure to perform.

Buyers of capacity, i.e. load-serving entities, pay an amount approximately equal to the quantity of capacity ISO-NE requires them to support in the power year, times the auction-clearing price for that power year.[17] The quantity of capacity that a particular load is required to hold in the power-year is set by ISO-NE and is called the Capacity Load Obligation (ISO-NE Market Rule 1 §III.13.7.3). This obligation is based on the estimated contribution of that load to the ISO annual peak in the preceding power year. Thus, the total cost of capacity to a load-serving entity for a given power year, i.e., required kW of capacity multiplied by FCA price in dollars per kW, is mostly set in advance of that power-year. The price is determined roughly three years in advance, and each load's individual share of the cost is set the summer before.

2.2.1.3. Energy Efficiency Programs and the Capacity Market

An energy efficiency program that produces a reduction in peak demand has the ability to avoid the wholesale capacity cost associated with that reduction. The capacity-cost amount that a particular reduction in peak demand will avoid in a given year will depend

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[14] If, in a given FCA, more capacity clears at the floor price than is required to satisfy the ICR, each cleared resource must accept downward proration of either the quantity of capacity that it bid or the final auction price. For example, if the capacity clearing at the market is roughly 6% above the net ICR (as in FCA 1), each resource must choose between being paid 94% of the floor price (about \$4.23 in FCA 1) for all its bid capacity, or the floor price for 94% of its bid capacity. In FCA 4, the excess remaining capacity at the floor price was 4,619 MW (about 14% above the NICR) and most resources will be paid \$2.54 for their bid capacity. Emergency generation and resources in Maine are subject to additional constraints and proration.

[15] ISO-NE posted the results of FCA 5 on June 27, 2011.

[16] Our analyses do not adjust for PER as it appears to be minimal, based on a review of estimates for 2007 through 2009.

[17] These costs will be reduced by the PER and credits for supplier performance penalties, as well as by adjustments due to reconfiguration auctions (in which the ISO can buy back unnecessary capacity obligations, or purchase additional obligations). Load-serving entities can also self-supply a portion of their capacity requirements.

upon the approach that the program administrator responsible for that energy efficiency program takes towards bidding all, or some, of that reduction into the applicable FCAs.

A program administrator (PA) can choose an approach that ranges between bidding 100% of the anticipated demand reduction from the program into the relevant FCAs to bidding zero percent of the anticipated reduction into any FCA.

- A PA that wishes to bid 100% of the anticipated demand reduction from the program into the relevant FCA has to do so when that FCA is conducted, which can be up to three years in advance of the program implementation year. For example, a PA responsible for an efficiency program that will be implemented starting January 2012 would have had to have bid 100% of the forecast demand reduction for June 2012 onwards from that program into FCA 3, which was held in 2009. Since a bid is a firm financial commitment, there is an associated financial risk if the PA is unable to actually deliver the full demand reduction for whatever reason. The value of this approach is the compensation paid by ISO-NE, i.e. the quantity of peak reduction each year times the FCA price for the corresponding year.
- If a PA does not bid any of the anticipated demand reduction into any FCA, the program can still avoid some capacity costs if it has a measure life longer than three years.[18] Under this approach, a PA responsible for an efficiency program starting January 2012 simply implements that program. The customers' contribution to the ISO peak load, whenever that occurs in the summer of 2012, would be lower due to the program. This PA's customers would see some benefit from a lower capacity share starting in June 2013 (the following year). The reduced capacity requirement will reduce the capacity acquired in future FCAs, starting as early as the reconfiguration auctions for the power year starting in June 2013 and affecting all the auctions for the power years from June 2016 onward; the entire region will benefit from the reduction of capacity purchases.

[18] In many cases, the PA is a utility; in other cases it is a state agency or other entity. In any case, the reduction in load benefits the customers served by the PA, whether they pay for generation supply through a utility standard-offer supply, an aggregator, or a competitive supplier.

2.2.2. Loads and Resources

2.2.2.1. Load Forecast

In order to forecast electric energy and capacity prices that would occur in the absence of new demand side management (DSM) programs, the project team developed a forecast of peak demand and energy requirements in the absence of new DSM programs.[19]

The forecasts of annual energy and peak load AESC 2011 uses to calculate avoided costs in AESC 2011 are derived from the ISO-NE 2011-2020 Forecast Report of Capacity, Energy, Loads and Transmission ("CELT 2011" or ISO-NE (2011)), as discussed below. Beyond 2020, AESC 2011extrapolates using the last five years of the long-term (2015–2020) Compound Annual Growth Rate (CAGR) reflected in that report.

Load Forecast for 2011 through 2020 (CELT 2011)

ISO-NE developed the CELT 2011 forecast of peak demand and energy requirements through 2020 based upon econometric models.[20]

The ISO forecasts annual energy for New England as a whole and for each individual state. ISO-NE (2011) is based on previous-year usage along with real electricity price, real personal income, gross state product and heating and cooling degree days (ISO-NE 2010b).[21] The ISO developed the model and its coefficients by analyzing the historical relationships between energy requirements and those independent variables since 1984. Therefore, the forecast implicitly assumes some level of reductions from efficiency programs because the programs in effect during the historical period would have influenced the actual level of energy use and be reflected in the derived model coefficients, most likely for the personal income and electricity price variables. However, it is difficult to estimate the size of the effect of prior DSM on the energy forecast. One way to calculate those effects would be to explicitly include the DSM energy savings and recalculate the model coefficients. This would be a fairly significant task to undertake and is beyond the scope of this Study. Such work would probably best conducted by ISO-NE.

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[19]The purpose of the overall the study is to develop avoided costs for program administrators to use in their economic evaluations of measures for inclusion in DSM program budgets for calendar years 2012 and beyond. The program administrators will submit those proposed budgets in regulatory filings from mid-2011 onward. If the program budgets are approved, the measures would be installed after January 1, 2012, causing savings from that point onward.

[20]Further information about the CELT forecasting process can be found at ISO-NE's web page, http://www.iso-ne.com/trans/celt/fsct_detail/2011/index.html as of April 23, 2011 .

[21] The CELT 2011 econometric model variables differ by state as shown in the "rsp11_ene_models.pdf" document on the above website.

For its forecast of peak-load, ISO-NE develops peak-load models for each calendar month, for New England as a whole and each state, using daily historic data. The models are based on the annual energy load, a temperature humidity index and several dummy variables for weekends and holidays. The historic and forecast loads are then explicitly modified by Passive Demand Resources (PDRs) based on DSM programs that qualified in the capacity market. These resources are called passive because they cannot be dispatched, but do have identified effects on loads and qualify as capacity resources.

CELT 2011 includes explicit calculations of PDR effects to develop its estimates of net peak and energy loads. CELT 2011 estimates that PDRs would lower the summer peak (relative to the econometric forecast) by 774 MW in 2011, 960 MW in 2012 and 1,148 MW in 2013.

The forecast of annual energy load AESC 2011 uses to calculate avoided costs is derived from the ISO-NE (2011) annual energy load forecast by excluding the effects of all post 2010 PDRs as reported in CELT 2010, i.e., 572 MW for peak loads and 3,545 GWh for energy.[22] These exclusions are consistent with estimating avoided-costs in the absence of future energy-efficiency effects.

The forecast of peak load AESC 2011 uses to calculate avoided costs is taken directly from ISO-NE (2011) since those resources can participate in the capacity market.

Load Forecast Post 2020

Beyond 2020, we extrapolate using the CAGR from the last five years reflected in the CELT 2011 forecast. AESC 2011 excludes the first five years of CELT 2011 when calculating the CAGR because load growth during that period of economic recovery is not representative of longer-term load growth within New England. For context, ISO-NE's (2011) long-term annual average rate of summer peak growth for the ISO-NE control area is 1.24 percent. The energy load growth is a little less at 0.98 percent.

The following two exhibits show ISO-NE's (2011) projections of net summer peak load and annual net energy consumption for ISO-NE relative to historic levels. Note that the historic values are actuals and represent the embedded effects of DSM programs whereas the forecasts do not.

[22] AESC 2011 used PDRs reported in CELT 2010 because the PDRS reported in CELT 2011 were not available at the time the annual load forecast was developed.

Exhibit 2-1: ISO-NE Peak Summer Load

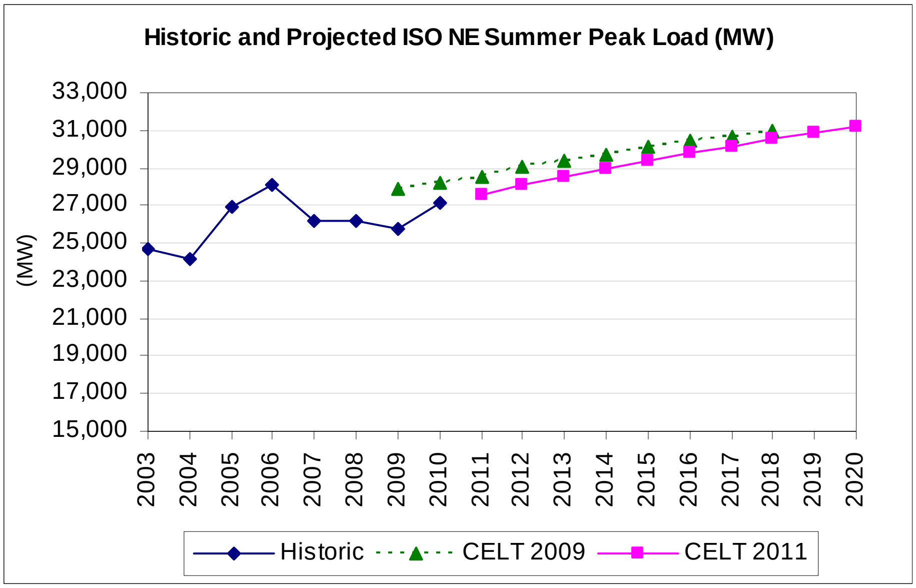
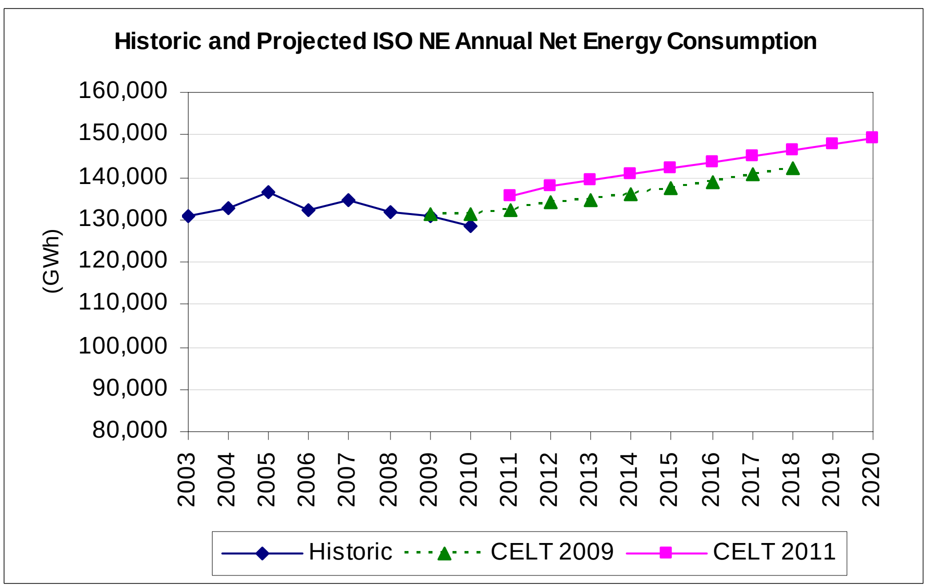


Exhibit 2-2: ISO-NE Net Annual Consumption



2.2.2.2. Transmission

The interface limits used in the simulations reflect the existing system, ongoing transmission upgrades including those discussed in the ISO-NE Regional System Plan, and the reference Market Analytics database. We also consider any congestion identified during our modeling.

The detailed transmission assumptions are closely related to the modeling topology and are presented in Section 2.3.2.3

2.2.2.3. Retirements

In general AESC 2011 assumes that plants that have been operating since the implementation of restructured markets will continue to operate in the absence of any major changes in market and regulatory conditions. AESC 2011 assumes that retirements of existing plants will be driven by the following factors:

- Requirements for environmental retrofits due to regulatory changes. A discussion of changing environmental and economic conditions that will drive retirements is presented in Section 2.2.3.
- Failure of major components in old and marginally cost-effective units. In these situations, restoring the plant to service may not be cost-effective. Component failure is inherently unpredictable. Our assumptions about the retirement of older capacity reflect anticipated effects of equipment failure.
- The expiration of nuclear, hydro or other licenses for plants that cannot economically meet requirements for license extension. We describe the relicensing of New England nuclear units in Section 2.3.2.4 .Relicensing of hydroelectric plants has resulted in reduced capacity or retirement of a few small units; we do not anticipate any significant effects on hydro capacity in the future.
- Construction of new capacity at the site of existing capacity, requiring retirement due to lack of space, transmission capacity or emission compliance restructuring of the New England electric-utility industry, several units have been retired in order to provide space for the construction of new generation. Those retired units include Mystic units 4–6 and the Edgar jets. No pending capacity additions are expected to drive retirements of existing units, even new additions being sited at existing plant sites, such as Middletown, New Haven, and Devon. When new generic units are added, some existing units on those sites may retire; we assume that the additions will offset the retirements with little effect on market prices.

2.2.2.4. Resource Additions

Over the course of the study period, new generation resources will be needed in addition to the existing mix of generating capacity in order to satisfy renewable portfolio standards, meet future load growth, and respond to retirements. Since Market Analytics is not a capacity expansion model, these additions are inputs to the model. Our assumptions regarding new capacity additions are presented below.

Additions to Meet Renewable Portfolio Standards

Each New England state has adopted some form of renewable portfolio standard or renewable energy standard (RPS). Connecticut, Maine, Massachusetts, New Hampshire and Rhode Island all have mandatory RPS requirements and require penalty payments for non-compliance. Vermont currently has a voluntary RPS, with a legislatively-driven option to convert to a mandatory requirement if the voluntary goal is not met.[23] A summary of the region's RPS requirements and eligibility criteria are summarized, by state and RPS sub-category is found in Appendix C.

The quantity of *new* or *incremental* renewables that will be added each year during the study period is driven by these requirements. In particular, new renewable additions are driven by demand from the "Premium RPS tiers" which consist of:

- "Class I" (Connecticut, Massachusetts, New Hampshire, Maine);
- "New" (Rhode Island) RPS tiers;
- The 'Class II' (solar) tier in New Hampshire; and
- The MA Solar Carve-Out[24]The MA Solar Carve-Out is the most recent addition to this set of standards, completing its first compliance year in 2010.

It is also important to note that while past experience has favored the creation of new or accelerated RPS requirements, the delay or reduction of future RPS targets is also proposed and discussed from time to time.

With the exception of Vermont, all states require the use and retirement of NEPOOL Generation Information System (GIS) certificates in order to demonstrate RPS compliance.[25] In the marketplace where this commodity is traded, NEPOOL GIS Certificates are often referred to as Renewable Energy Certificates (RECs). While the definition of a GIS Certificate is narrower than that of a REC, the two terms are used interchangeably and their reciprocal meaning is commonly understood.

The gross demand for new renewable generation resources is derived by multiplying the load of obligated entities (those retail load-serving entities subject to RPS requirements, often excluding public power) by the applicable annual RPS percentage target for the RPS Tier.

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[23] Vermont has also recently initiated a study to identify RPS best practices and quantify the potential costs and benefits of implementing a mandatory RPS. A report is due to the legislature in October 2011.

[24] The Massachusetts Solar Carve-Out is technically a sub-component of the MA Class 1 RPS target.

[25]Currently, Vermont's requirement will allow RECs to be sold off elsewhere (presumably for compliance in other states), therefore not leading to incremental renewable-energy additions beyond what would be predicted in the presence of other states' requirements. (However, it has been argued that the Vermont requirements will support financing and therefore lead to more renewables being built and therefore less reliance on Alternative Compliance Payments). We assume that by 2013, Vermont's standard will be altered to require retirement of RECs, and which increase the total RPS additions we project.

The net demand for incremental renewable generation within New England is derived by subtracting from the gross demand: (a) existing eligible generation already operating (including biomass co-fired at existing fossil-fueled facilities); and (b) the current level of RPS certified imports.

Over time, the net demand to be met by resources within ISO-NE will be further reduced by an estimate of additional RPS-eligible imports over existing tie lines, phased in towards a maximum level of usage (consistent with competing uses of the lines and appropriate capacity factors of imported resources) at a rate consistent with the recent historical rate of increase in RPS-eligible imports over a ten-year period.

Renewable resources eligible to satisfy state RPS requirements have considerable overlap, but vary by state. From approximately 2015 onward AESC 2011 assumes that renewable resources eligible in one or only a few states are insufficient to completely fulfill the demand of the limited states in which they are eligible. In effect, we assume that beyond 2015 every state in New England is competing at the margin to satisfy its requirements for new renewables, other than the solar tiers, from the same group of eligible supply resources.

In the near term (from 2012 to 2016), we assume that the aggregate net RPS demand for new renewable energy will be met by a mix of renewable resource generation consistent with: (1) RPS-eligible resources in the New England administered systems and Maine Public Service interconnection queues, plus (2) other expected RPS-eligible generation in the development pipeline, which has not entered the queue. This includes both large projects which have not yet filed for interconnection studies and distributed wind, solar and fuel cell projects, which- due to their size- are not required to go through the large generator interconnection process. Due to the increasing expense of entering and maintaining a position in the interconnection queue, some proposed projects must delay this stage of the process until early site evaluation and permitting progress has been sufficient to attract substantial development capital.

In some cases, the development and interconnection processes are also delayed by regulatory uncertainty. The critical example in today's market is the Massachusetts Department of Energy Resources' (DOER) revision of the RPS-eligibility of biomass generators and feedstock. A lengthy stakeholder and rule promulgation process has delayed the development of nearly all of the region's proposed biomass projects. The DOER's most recent draft RPS regulation was filed on May 3, 2011 and is now subject to legislative committee review. DOER will incorporate the legislature's comments and then promulgate final regulations. This analysis takes into account the fuel sustainability, efficiency, and other standards found in these near-final regulations. The changes are expected to cause not only project delays but also changes in the scale and configuration of proposed projects. The overall probability of success for all proposed biomass projects has been reduced as a result.

All proposed generators for which information has entered the public domain are included in this analysis. This generation is derated to reflect the likelihood that not all proposed projects will ultimately be built, and may not be built on the timetable reflected in the queue. This information is grouped by load area as an input to the Market Analysis model.

For the longer term (generally after 2015), we estimate the quantity and types of renewables that will be developed using a supply-curve approach based on resource potential studies. In this approach, potentially available resources are sorted from least to greatest REC premium required to attract financing. This approach identifies the incremental resources required to meet net incremental demand in each year through 2026.

The one exception to this methodology is solar PV. We assume that resource is developed in proportion to various state policies intended to promote solar, including solar RPS tiers and other factors.

In this work we assume full compliance with established RPS requirements via one of two possible mechanisms. First, entities subject to RPS requirements are expected to comply primarily through the acquisition and retirement of GIS Certificates/RECs. In the alternative, an obligated entity can comply with RPS requirements by making an Alternative Compliance Payment (ACP).[26] ACP levels have been set at prices above the minimum REC price level expected to be necessary to allow plants to be financed and built. Because of the presence of the ACP as a valid form of compliance, actual non-compliance with RPS requirements will be extremely rare. In other words, if the market is short on supply, there is a valid alternative route to comply. Given these options we expect load-serving entities to comply each year, particularly since regulators have the authority to impose penalties or ultimately withdraw the generator's right to participate in the RPS market.

Planned Additions and Uprates

The non-renewable generation resources used as inputs to our simulations are drawn from the capacities in ISO-NE (2011). Exhibit 2-9 below (page 2-36) lists the specific

[26]In Massachusetts, Rhode Island, New Hampshire, and Maine, the Class-I or new-renewables tiers utilize an ACP mechanism set at a common level. For these states, the ACP is $62.13/MWh in 2011, and increases with inflation thereafter. In Connecticut, the penalty for non-compliance is set at $55/MWh., with no annual escalation. While it is called a penalty rather than ACP in Connecticut, its effect is similar and it is often referred to as an ACP, which has become the generic term of art in the industry.

generation additions we assume beyond that. These are primarily the new units that are under contract to the Connecticut utilities and those under construction for municipal utilities, and include the generators that cleared in the Forward Capacity Auctions.

Demand-Response Resources

Demand Response (DR) resources participate in the FCA. For simulation purposes we start with the quantities of DR that cleared in FCA 4 and project quantities for future FCAs. DR resources, when dispatched, affect energy prices primarily in peak hours.

Generic Non-Renewable Additions

New generic non-renewable resources will be added to meet any residual installed capacity requirements after adding planned and RPS additions. We developed our assumptions regarding the quantity, type, and timing of these generic additions in coordination with our simulation of the FCM because revenues from FCA prices help support those investments.

Based on the mix of resources in the interconnection queue, and the constraints on construction of new coal or nuclear units in New England in the foreseeable future, we assume generic additions comprising gas-oil-fired 490-MW combined-cycle (CC) units and 180-MW combustion turbines (CT). These additions are dispersed throughout New England based on zonal need and historical zonal capacity surplus-deficit patterns.

2.2.3. Environmental Regulations

Market Analytics has the ability to model, and apply, unit costs of compliance for multiple emissions. For AESC 2011, we modeled the costs of complying with regulations governing the emissions of SO_2, NO_x and CO_2. The model includes the unit costs associated with each of these emissions when calculating bid prices and making commitment and dispatch decisions.[27] In this way AESC 2011 projects market prices which reflect, or "internalize" the unit-compliance costs for each emission, except mercury. The unit compliance costs assumed for each pollutant are presented in Exhibit 2-3.

The assumptions for NO_x and SO_2 allowances are based on the Market Analytics default data and consistent with the current futures prices.[28] Since there is still considerable

[27] These are the carbon values that are internalized in the cost of electricity. For a discussion of the overall cost of carbon, including its externality/climate plan compliance cost and overall value, see Chapter 6.

[28]NOx allowance prices have fallen considerably since the previous AESC report in 2009. The NOx prices in AESC 2009 started at $1,500 and fell to $284. The SO_2 prices are also much lower than AESC 2009 where they started at $60.8 and fell to $4.83 per ton. Compared to AESC 2009, CO_2 prices are approximately 50% lower for RGGI and start five years later for the Synapse forecast.

uncertainty about the longer term we have kept NO_x and SO_2 prices at level constant 2011 dollar (2011$) values. For mercury, we assume no trading, and hence no allowance price. CO_2 prices are based on RGGI prices through 2017 and thereafter they are based on assumed prices under Federal regulation according to the February 2011 Synapse carbon dioxide price forecast.[29] [30]

The following explanation for the Market Analytics NOx and SO2 emission price forecasts is from the Ventyx Database Release Notes of February 2011. Further discussion of EPA regulations is in the next section.

> As with previous releases, Ventyx Advisors continue to project both the emissions market prices for NO_X and SO_2, and the necessary emissions controls that will be installed on generators to meet federal as well as local air quality limits. Beginning with this data release (NERC 9.1), NOx and SO2 forecasts reflect the Federal Clean Air Transportation Rule (CATR) rather than the previously modeled Federal Clean Air Interstate Rule (CAIR) due to the DC Circuit Court vacating CAIR in 2008 and EPAs response of CATR. Given the differences in the programs being modeled including their reduction requirements and geographic scope, it may not be entirely appropriate to compare these prices graphically – nonetheless they are provided for information and with the caveat that they are different programs. Note that higher emissions requirements in CATR for NOx have resulted in requirements being already met and thus there is no marginal cost of compliance (or emissions penalty).

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[29] Johnston et al, "2011 Carbon Dioxide Price Forecast", February 2011. http://www.synapse-energy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf

[30] See footnote 15.

Exhibit 2-3: Emission Allowance Prices per Short Ton (2011$ and Nominal Dollars)

	NOx		**SO_2**		**CO_2 (Synapse)**		**CO_2 (RGGI)**	
Year	2011$	Nominal	2011$	Nominal	2011$	Nominal	2011$	Nominal
2011	$230	$230	$3.75	$3.75	$1.89	$1.89	$1.89	$1.89
2012	145	148	3.21	3.27	1.89	1.93	1.89	1.93
2013	134	139	1.65	1.72	1.89	1.97	1.89	1.97
2014	132	141	1.62	1.72	1.89	2.01	1.89	2.01
2015	*132*	143	*1.62*	1.75	1.89	2.05	1.89	2.05
2016	*132*	146	*1.62*	1.79	1.89	2.09	1.89	2.09
2017	*132*	149	*1.62*	1.83	1.89	2.13	1.89	2.13
2018	*132*	152	*1.62*	1.86	15.30	17.57	1.89	2.17
2019	*132*	155	*1.62*	1.90	18.28	21.41	1.89	2.21
2020	*132*	158	*1.62*	1.94	21.25	25.40	1.89	2.26
2021	*132*	161	*1.62*	1.98	24.23	29.53	1.89	2.30
2022	*132*	165	*1.62*	2.02	27.20	33.82	1.89	2.35
2023	*132*	168	*1.62*	2.06	30.18	38.27	1.89	2.40
2024	*132*	171	*1.62*	2.10	33.15	42.88	1.89	2.44
2025	*132*	175	*1.62*	2.14	36.13	47.67	1.89	2.49
2026	*132*	178	*1.62*	2.18	39.10	52.62	1.89	2.54
2027	*132*	182	*1.62*	2.23	42.08	57.76	1.89	2.59
2028	*132*	185	*1.62*	2.27	45.05	63.08	1.89	2.65
2029	*132*	189	*1.62*	2.31	48.03	68.59	1.89	2.70
2030	*132*	193	*1.62*	2.36	51.00	74.30	1.89	2.75

NOx & SO_2 from CCE March 2011 through 2014, level thereafter. CO2 (RGGI) from 11th auction, CO2 (Synapse) starting in 2018 from Synapse report of February 2011.

2.2.3.1. EPA Regulations

The EPA is in the process of numerous rulemakings, many of them court-ordered, which implement statutory requirements under the Clean Air Act, Clean Water Act and Resource Conservation and Recovery Act (RCRA). Several of these rules will regulate the power sector directly. These include revisions of Clean Air Act new source performance standards for power plants, regulation of interstate pollutant emissions from power plants, regulation of hazardous air pollutant emissions from power plants, haze regulations, new standards governing cooling intake water, and new effluent limitation guidelines for wastewater discharges from power plants. In addition, EPA has proposed to regulate the disposal of coal combustion wastes for the first time. Finally, the EPA is in the process of revising several National Ambient Air Quality Standards (NAAQS) for pollutants including particulate matter (PM), ozone, sulfur dioxide, and nitrogen oxides. Revised NAAQS will result in the designation of additional nonattainment areas, which in turn will obligate states to require emissions reductions from major pollution sources including power plants.

When considered individually, these rules to varying extents will require retrofits and associated outages and may result in retirements and/or the repowering of existing electric generating units across the United States. Taken together, these rules will have a significant effect on the generating fleet.

Following is a short description of the rules anticipated to have the most economically consequential impacts on the power sector. Appendix C provides a summary description of these rules and a timeline of their anticipated implementation

Clean Air Transport Rule (CATR)

The Clean Air Transport Rule, proposed in July 2010, will reduce emissions that contribute to non-attainment of National Ambient Air Quality Standards or that interfere with maintenance of those standards by downwind states.[31] Based on the current proposal, emissions of sulfur dioxide and nitrogen oxide from electric generating units in 31 eastern states and the District of Columbia will be capped to help enable downwind states to comply with the NAAQS, including the annual $PM_{2.5}$ NAAQS (promulgated in 1997) and the 24 hour $PM_{2.5}$ NAAQS (promulgated in 2006).[32] Compliance with the transport rule will require substantial investments in scrubbers and other control devices at many generation stations.

Air Toxics Standards (MACT Rule)

The EPA is under court order to set emission limits for hazardous air pollutant emissions from electric generating units under section 112(d) of the Clean Air Act. More than 180 hazardous air pollutants are listed under the Clean Air Act, and those most relevant to the electric power industry include mercury, dioxins, and acid gases. This "air toxics rule" would require that sources meet emission limits based on EPA's assessment of "Maximum Achievable Control Technology" or "MACT." For existing sources, this means that the level of control achieved must be in line with the average of the top twelve percent of top-performing power plants. Requirements for new sources are at least as stringent as the single best performing source, reflecting the maximum emissions reductions achievable with state-of-the-art pollution controls. Existing units will have three years to comply with the final rule once it is issued, while new sources will have to comply immediately upon issuance of the rule.[33] The EPA issued the new proposed rule

[31] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010 / Proposed Rules, pp. 45210 ff.

[32] US EPA, Office of Air and Radiation. *Proposed Air Pollution Transport Rule*. July 26, 2010. Slide 4. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf.

[33] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 17. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.

in March 2011 and is expected to finalize the rule in November 2011.[34] New standards must be implemented within three years after the rule is finalized, so compliance by 2014 is implied.

The EPA has not yet released an analysis of costs and benefits of the MACT rule. However, as discussed below, several recent analyses assess their impact on the power sector.

Coal Combustion Residuals

Coal combustion residuals are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and flue gas materials. . The EPA's long-term objective is to phase out the wet handling of coal ash and the use of surface impoundments (ash ponds) in favor of dry ash handling and disposal in lined landfills. Approximately one-third of the coal capacity in the United States uses wet ash handling and storage systems.[35]

Clean Water Act § 316(b)

Thermal power plants using water for cooling purposes use one of three types of cooling systems: once-through, recirculating, and dry cooling. Once-through systems withdraw water in large volumes and then discharge it back into the same water body at elevated temperatures. Recirculating systems withdraw water in smaller volumes, and continuously circulate the cooling water through a plant's heat exchangers with the aid of cooling towers. Dry cooling systems are closed-loop systems that do not rely on cooling water, but instead on forced draft air flow.

Section 316(b) of the Clean Water Act requires that new power plants use the best available cooling water intake technologies for minimizing adverse environmental impacts. Adverse environmental impacts include the intake of aquatic organisms with cooling water when using once-through systems.

Regional Haze Rule

The Clean Air Act defines as a national goal the remedying of existing visibility impairment that results from manmade air pollution in all "Class I" areas (e.g., most national parks and wilderness areas). See 42 U.S.C. § 7491(a)(1). EPA's implementing rules require states to create plans to achieve natural visibility conditions by 2064 with enforceable reductions in haze-causing pollution from individual sources and other

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[34] US EPA, Office of Air and Radiation. *Reducing Air Pollution from Power Plants*. September 24, 2010. Slide 7. Available at: http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20AIR%20Presentation%20Sept%2024%202010%20_%20Sam%20Napolitano.pdf.

[35] Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 66.

measures to meet "reasonable further progress" milestones. See generally 40 C.F.R. §51.308-309.

New Source Review

Changes in EPA regulations for New Source Review (NSR) may affect the economics of keeping some existing plants in operation which we will consider on a case by case basis.

2.2.3.2. CO_2 Regulation

AESC 2011 assumes RGGI allowances prices as reported in Exhibit 2-3 based upon recent auction results which have been at the reserve price and are likely to remain so in the future. At the 11th quarterly RGGI auction held March 9, 2011, the allowances for the current and future control periods cleared at the reserve price of $1.89.[36]

After 2017, we use prices estimated by Johnston et al. (2011) for our Reference Case, in which a national cap-and-trade program for GHG is enacted.[37] From 2026 onward, we assume allowance prices in the Reference Case will rise at the rate of inflation.

As requested, we have also estimated CO_2 allowance prices for a special case that assumes no new Federal regulatory framework and thus continuation of RGGI indefinitely (RGGI-only). We do not believe this case is likely. Under the RGGI-only scenario we assume that RGGI prices will remain relatively stable due to electricity imports. Thus, we assume allowance prices in that RGGI-only case will rise at the rate of inflation.

2.2.4. Results of Forward Capacity Auctions and Regional Greenhouse Gas Initiative Auctions

Results of Forward Capacity Auctions

As noted in Section 2.2.1.2, revenues from FCAs will influence decisions regarding continued operation of existing generating units and investments in new generating units.

Results of Regional Greenhouse-Gas-Initiative Auctions

As noted in Section 2.2.3.2, the 11th RGGI auction was held in March of 2011. The current and future control period allowances cleared at the reserve price of $1.89. Considering future RGGI requirements, the modest expected load growth in the Northeast and the effect of RPS programs, we expect future RGGI auctions to also clear at the reserve price. New England states use revenues from RGGI auctions to fund state energy efficiency and renewable energy programs. This is discussed more fully as described above.

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[36] Accessed 3/21/11 at http://www.rggi.org/docs/Auction_11_Release_Report.pdf

[37] Johnston (2011)

2.3. Wholesale Electric Energy Market Simulation Model and Inputs

2.3.1. The Energy-Market-Simulation Model

Market Analytics is a zonal locational marginal-price-forecasting model that simulates the operation of the energy and operating reserves markets. The simulation engine used is PROSYM. The modeling system and the default data is provided by the model vendor Ventyx.

The model does not simulate the forward capacity market and, therefore, does not require assumptions regarding the capital costs of new generation capacity, and the interconnection costs associated with such capacity. However, the model does require assumptions about the quantity and type of existing and new capacity over the study horizon.

Market Analytics also requires assumptions of monthly regional prices of fuels used to generate electricity. Those -prices forecasts are described in Chapter 3 and 5. The remaining inputs are discussed in the sections below.

2.3.1.1. Zonal Locational Marginal Price-Forecasting Model

The following section provides a high-level overview of the Market Analytics data-management and production-simulation-model functionality. Market Analytics uses the PROSYM simulation engine to produce optimized unit commitment and dispatch options. The model is a security-constrained chronological dispatch model that produces detailed and accurate results for hourly electricity prices and market operations.

The smallest location in Market Analytics is a Location (typically representing a utility service territory) which for modeling purposes is mapped into a Transmission Area (TA). A TA may represent one or more Locations. Transmission areas represent sub regions of Control Areas such as ISO New England. Transmission areas are defined in practice by actual transmission constraints within a control area. That is, power flows from one area to another in a control area are governed by the operational characteristics of the actual transmission lines involved. PROSYM can also simulate operation in any number of control areas. Groups of contiguous control areas were modeled in order to capture all regional impacts of the dynamics under scrutiny.

PROSYM uses highly detailed information on generating units. Data on specific units in the Market Analytics database are based on data drawn from various sources including the U.S. Energy Information Administration, U.S. Environmental Protection Agency, North American Electric Reliability Corporation, Federal Energy Regulatory Commission (FERC), and ISO-New England databases as well as various trade press announcements and Ventyx's own professional assessment. Total existing capacity in the Market Analytics database was compared with that of ISO-NE CELT 2011 and found to be reasonably consistent, although we made a few adjustments to reflect retirements as detailed below.

For larger units, emission rates and operating characteristics are based on unit-specific data reported to EPA and EIA rather than on data based on unit type. Operating costs for each unit are based on plant-level operating costs reported to FERC and assessment of unit type and age. For smaller units (e.g., combustion turbines), most input data are based on unit type. All generating units in PROSYM operate at different heat rates (efficiencies) at different loading levels. This distinction is especially important in the case of combined-cycle units, which often operate in a simple-cycle mode at low loadings. PROSYM determines the fuel a unit burns by placing each generating unit into a "fuel group." PROSYM does not limit the number of fuel groups used, and creating new fuel groups to simulate a few unusual units is a simple matter. In New England, for example, it is especially important to model the operation of dual-fueled units as accurately as possible.

Based upon hourly loads, PROSYM determines generating unit commitment and operation by transmission zone based upon economic bid-based dispatch, subject to system operating procedures and constraints. PROSYM operates using hourly load data and simulates unit dispatch in chronological order. In other words, 8,760 distinct hourly load levels are used for each transmission area for each study year. The model begins on January 1st and dispatches generating units to meet load in each hour of the year. Using this chronological approach, PROSYM takes into account time-sensitive dynamics such as transmission constraints and operating characteristics of specific generating units. For example, one power plant might not be available at a given time due to its minimum down time (i.e., the period it must remain off line once it is taken off). Another unit might not be available to a given transmission area because of transmission constraints created by current operating conditions. These are dynamics that system operators wrestle with daily, and they often cause generating units to be dispatched out of merit order. Few other electric system models simulate dispatch in this kind of detail.

The model's fundamental assumption of behavior in competitive energy markets is that generators will bid their marginal cost of producing electric energy into the energy market. The model calculates this marginal cost from the unit's opportunity cost of fuel or the spot price of gas at the location closest to the plant, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions.

PROSYM does not make capacity-expansion decisions internally. Instead, the user specifies capacity additions, a practice that increases transparency and allows the system-expansion plans to be specified to reflect non-market considerations. As discussed in more detail, PROSYM also models randomly occurring forced outages of generating units probabilistically rather than as deterministic capacity de-rating, thereby producing more accurate estimates of avoided costs, particular for peak-load periods. PROSYM models generating units with a much higher level of detail including inputs for unit specific ramp rates, minimum up/down times, and multiple capacity blocks, all of which are critical for accurately modeling hourly prices. This modeling capability enabled production of locational prices by costing period in a consistent manner at the desired level of detail.

PROSYM simulates the effects of forced (i.e., random) outages probabilistically, using one of several Monte Carlo simulation modes. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo–type random number draw. Many other models simulate the effect of forced outages by “de-rating” the capacity of all generators within the system. That is, the capacities of all units are reduced at all times to simulate the outage of several units at any given time. While such de-rating usually results in a reasonable estimate of the amount of annual generation from baseload plants, the result for intermediate and peaking units can be inaccurate, especially over short periods.

PROSYM calculates emissions of NO_x, SO_2, CO_2 and mercury based on unit-specific emission rates. Emissions of other pollutants (e.g., particulates and air toxics) are calculated from emissions factors applied to fuel groups.

2.3.2. Input Assumptions to Electric-Energy-Price Model

The input assumptions to the Market Analytics locational-price-forecasting model include market rules and topology, hourly load profiles, forecasted annual peak demand and total energy, thermal-unit characteristics, conventional hydro and pumped storage unit characteristics, fuel prices, renewable unit characteristics, transmission system paths and upgrades, generation retirements, additions and uprates, outages, environmental regulations, and demand-response resources.

2.3.2.1. Market Rules and Topology

The major assumptions are described below as inputs to the model.

Marginal-Cost Bidding

In deregulated markets generation units are assumed to bid marginal cost (opportunity cost of fuel plus variable operating and maintenance costs (VOM) plus opportunity cost of tradable permits). It is reasonable to assume that the real markets are not perfectly competitive and thus the model prices based on marginal costs tend to underestimate the prices in the real markets. To represent that effect we investigated bid adders to represent more realistic market behavior. The resulting energy-price outputs are benchmarked against historic and futures prices.

Installed Capacity

Installed-capacity requirements for the resource-addition model include reserve requirements established by ISO-NE on an annual basis. Current estimates of the reserve-margin and installed-capacity requirement (with and without the Hydro Quebec (HQ) installed capacity credits) as described in Chapter 6. Installed capacity for the energy model in each model year will be consistent with the values assumed in the FCA analysis, although the values will not be the same, due to imports and exports.

Ancillary Services

Market Analytics allows users to define generating units based on their ability to participate in various ancillary services markets including Regulation, Spinning Reserves, and Non-Spinning Reserves. The database includes specifications for these abilities based on unit type. Market Analytics generates prices for these markets in conjunction with the energy market. The spinning reserves market affects energy prices since units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled. Reserves requirements for New England are applied to the model.

Electric Model Topology

Market Analytics represents load and generation areas at various levels of aggregation. Assets within the model, including physical or contractual resources such as generators, transmission links, loads, and transactions, are mapped to physical locations which are then mapped to transmission areas. Multiple transmission areas are linked by transmission paths to create the control area.

The load and generation areas to be modeled are presented in Exhibit 2-4 below.

CELT 2011 reports load for thirteen subareas. Those load areas correspond to the locations used in the Market Analytics data. Our modeling maps those thirteen load subareas into ten transmission areas, which is the level of detail required to report results for the fourteen zones specified for AESC 2011.[38]

Neighboring regions that are modeled in this study are New York, Quebec Ontario, and the Maritime Provinces.[39] Areas outside of New England are represented with a high level of zonal aggregation to minimize model run time.

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[38] We produce results for four of the AESC zones by aggregating the results for certain of the areas we model. For example, the results for Massachusetts is the aggregate results for SEMA, WCMA, and NEMA.   The results for the aggregate zones are based on the weighted averages of their constituent subzones.

[39]The Maritimes zone includes Maine Public Service (MPS) and Eastern Maine Electric Cooperative (EMEC) which are not part of ISO-New England and, therefore, are not included in any of the New England pricing zones

Exhibit 2-4: Load Areas Used to Model New England

	AESC Zones	Load Area CELT SubArea (13)	Market Analytics Modeling Areas (10)	AESC Zone Mapping
1	Maine	ME + BHE + SME	BHE + ME Central + ME Southwest	Direct
2	Vermont	VT	Vermont	Direct
3	New Hampshire	NH	New Hampshire	Direct
4	Connecticut (Statewide)	CT		*Aggregated*
5	Massachusetts (Statewide)	BOST + CMA/NEMA + SEMA + WMA		*Aggregated*
6	Rhode Island	RI	Rhode Island	Direct
7	SEMA (Southeast Massachusetts)	SEMA	MA Southeast	Direct
8	WCMA (West-Central Massachusetts)	WMA	MA Western	Direct
9	NEMA (Northeast Massachusetts)	(CMA/NEMA)	MA Central-Northeast	Direct
10	Rest of Massachusetts (Massachusetts excluding NEMA)	BOST + (CMA/NEMA) + SEMA + WMA		*Aggregated*
11	Norwalk/Stamford	NOR	CT Norwalk	Direct
12	Southwest Connecticut, including Norwalk/Stamford	SWCT		*Aggregated*
13	Southwest Connecticut, excluding Norwalk/Stamford	SWCT - NOR	CT Southwest	Direct
14	Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)	CT - SWCT	CT Central-Northeast	Direct

This study explicitly models neighboring control areas that have direct connections to the New England grid, including New York ISO, the Maritimes region (New Brunswick, Nova Scotia, and Prince Edward Island), and Quebec. These external markets are modeled in the same manner and simultaneously with New England. The Market Analytics database is used as the primary data source for external regions. New capacity is added to meet RPS requirements and generic gas capacity is added based on the same methodology that is used in New England.

The forecasts of electricity prices for each load area from the model are mapped and load-weighted into the AESC zones.

used in this study. MPS and EMEC are not modeled as part of the Maine pricing zone and were modeled as part of the New Brunswick transmission area.

2.3.2.2. Load Forecast

Forecasts of peak demand and annual energy by year for each of the ten areas modeled in Market Analytics were derived from ISO-NE (2011) as described in Section 2.2.2. Historical profiles for each utility were developed by Ventyx for Market Analytics based on a set of annual historical load shapes. Hourly load profiles based on historical profiles were calculated for each load serving entity. Loads were then mapped to transmission areas based on location ratios. Hourly load data for future years were scaled based on forecasted annual peak demand and total energy.

The area ISO-NE load forecasts are used to produce the transmission area loads required for the Market Analytics modeling.

Exhibit 2-5: Summer Peak Forecast by Model Load Area

Load Area	2011 (MW)	2020 (MW)	2015- 2020 CAGR	2026 (MW)
BHE	306	356	1.47%	389
ME	962	1,087	1.14%	1,164
SME	698	818	1.67%	903
NH	2,004	2,369	1.69%	2,619
VT	1,201	1,366	1.21%	1,469
BOST	5,616	6,301	1.12%	6,735
CMA/NEMA	1,710	1,965	1.38%	2,133
WMA	2,147	2,442	1.23%	2,628
SEMA	2,845	3,180	1.07%	3,390
RI	2,490	2,915	1.58%	3,203
CT	3,438	3,853	1.10%	4,114
SWCT	2,285	2,560	1.09%	2,732
NOR	1,271	1,436	1.15%	1,538
ISO-NE	**26,973**	**30,648**	**1.24%**	**33,016**
2026 values were developed by growing 2020 values by 2015-2020 Compound Annual Growth Rate.				
Loads include the effects of 2010 Passive Demand Resources.				

Exhibit 2-6: Energy Forecast by Model Load Area

Load Area	2011 (GWh)	2020 (GWh)	2015- 2020 CAGR	2026 (GWh)
BHE	1,830	1,980	0.78%	2,161
ME	5,806	6,216	0.69%	6,654
SME	3,959	4,334	0.92%	4,787
NH	10,291	11,746	1.35%	12,986
VT	6,981	7,651	0.80%	8,226
BOST	26,832	29,412	0.95%	31,436
CMA/NEMA	8,070	8,965	1.09%	9,732
WMA	10,624	11,684	0.98%	12,575
SEMA	13,774	15,199	1.02%	16,203
RI	11,478	13,033	1.28%	14,320
CT	15,825	17,320	0.82%	18,494
SWCT	10,579	11,589	0.83%	12,367
NOR	5,862	6,477	0.94%	6,938
ISO-NE	**131,911**	**145,606**	**0.98%**	**156,879**
2026 values were developed by growing 2020 values by 2015-2020 Compound Annual Growth Rate.				
Loads include the effects of 2010 Passive Demand Resources.				

2.3.2.3. Transmission Upgrades

Transmission-path assumptions were based on those developed by Market Analytics based on the transmission paths represented in ISO-NE (2010b). We have modified those based on ISO data and proposed projects to represent future additions. These transmission assumptions, like our other resource assumptions, are not intended to represent specific forecasts or projections, but a reasonable allowance for likely, but unknown additions.

The transmission system within Market Analytics is represented by links between transmission areas. These links represent aggregated actual physical transmission paths between locations. Each link is specified by the following variables: (a) “From” location, (b) “To” location, (c) Transmission capability in each direction, (d) Line losses in each direction and (e) Wheeling charges.

- “From” location
- “To” location
- Transmission capability in each direction
- Line losses in each direction
- Wheeling charges

Exhibit 2-7 shows the transmission capabilities of each path between New England zones and between New England and external areas as indicated in the Market Analytics database, reconciled to the interface limits reported in recent ISO reports. The exhibit below shows the transmission capability assumptions of each path.

Exhibit 2-7: Existing Transmission Paths and Future Upgrades

Path Type	Path Name	"From" TransArea	"To" TransArea	Capacity "From-To" (MW)	Notes	Capacity Back (MW)	Notes
Transmission Paths within New England	BHE-ME	BHE	ME	1,200		1,050	
	CMA-BOSTON	CMA-NEMA	BOST	3,200		3,000	
	CMA-NH	CMA-NEMA	NH	912		925	
	CMA-WMA	CMA-NEMA	WMA	1,360		2,000	
	CT-RI	CT-CNE	RI	720		797	(a) part of CT import
				1,170	1/1/2016	1,247	(b) 1/1/2016
	CTSW-CT	CT-SW	CT-CNE	2,000		3,500	
	CTSW-NOR	CT-SW	CT-NOR	1,650		1,650	
	MPS-BHE	MPS	BHE	10		10	
	NH-BOSTON	NH	BOST	900		912	
	NH-SME	NH	SME	1,400		1,475	
				2,400	1/1/2014	2,475	(c) 1/1/2014
	NH-VERMONT	NH	VT	720		715	
	RI-BOSTON	RI	BOST	400		400	
	RI-CMA	RI	CMA-NEMA	1,480		720	
	RI-SEMA	RI	SEMA	1,000		3,000	
	SEMA-BOSTON	SEMA	BOST	400		400	
	SME-ME	SME	ME	1,250		1,150	
	VERMONT-WMA	VT	WMA	875		875	
	WMA-CT	WMA	CT-CNE	980		1,085	(a) part of CT import
				1,480	1/1/2014	1,585	(d) As of 1/1/2014
Transmission Paths between New England and External Control Areas	BHE-NBPC	BHE	NBPC	425		1,000	
	CMA-HYQB (Phase II)	CMA-NEMA	HYQB	1,457		1,400	
						2,400	(e) As of 1/1/2020
	EMEC-NBPC	EMEC	NBPC	20		20	
	HYQB-VT (Highgate)	HYQB	VT	200		170	
	MPS-NBPC	MPS	NBPC	100		100	
	NOR-NYZK	CT-NOR	NYZK	100		80	
	NYZD-VERMONT	NYZD	VT	86		150	(f) part of NY-NENG
	NYZF-WMA	NYZF	WMA	330		650	(f) part of NY-NENG
	NYZG-CT	NYZG	CT-CNE	558		618	(f) part of NY-NENG
	NYZK-CT (CSC)	NYZK	CT-CNE	346		330	

Notes

(a) Connecticut import total of 2,500 MW distributed among several paths.
(b) Interstate Reliability Project (IRP) or equivalent increase CT-RI ties by 450 MW by 2016.
(c) Increased Maine interconnection associated with the Maine Power Reliability Project (MPRP) of 1000 MW in 2014.
(d) GSRP increases CT-WMA ties by 500 MW by 2016. Total CT ties increased by 950 MW of 1,100 MW proposed for NEEWS.
(e) Increased import capacity of 1000 MW from Quebec based on a number of proposals.
(f) Based on NY - New England import limit,

The New England East-West Solutions ("NEEWS) transmission program consists of four major components:

1) The Rhode Island Reliability Project (RIRP),

2) The Greater Springfield Reliability Project (GSRP),

3) The Interstate Reliability Project (IRP),

4) The Central Connecticut Project (CCP).

ISO-NE transmission-planning documents have assumed that Connecticut import capability will increase by 1,100 MW from NEEWS. AESC 2011 assumes increases of 950 MW of the 1,100 MW proposed under the IRP and GSRP components of NEEWS, both of which have been approved by the relevant state siting agencies and are under construction.

- 500 MW is effective in 2014 from the Western Massachusetts–Connecticut transfer capacity, reflecting the effect of the GSRP;
- 450 MW is effective in 2016 from the IRP. This timing is based on the experience of the GSRP. Allowing time for project design, review of alternatives, and preparation of siting filings, the siting filings for the final design of the IRP would be expected in 2012. The GSRP required approval in two states; the IRP will apparently require siting review in three states (Massachusetts, Rhode Island and Connecticut). Hence, 2016 appears to be a realistic in-service date for the next phase of NEEWS for our modeling purposes.

Most of the additional transfer capability into Connecticut (and on the East-West and SE Massachusetts–Rhode Island export interfaces as well) results from the IRP and CCP. These two projects were justified primarily by the objective of meeting Connecticut's load with combined generation and transmission outages at times of extraordinary (once in ten year) high-load conditions, even if more than 1,200 MW of Connecticut generation is retired. Since the original analyses, Connecticut has contracted for over 1,500 MW of additional capacity, load forecasts have fallen, and the GSRP is expected to increase import capacity, greatly reducing the prospect of shortfalls in the Connecticut transmission-security analysis. As a result, both the IRP and CCP have been subject to reconsideration by the ISO.

In consideration of a number of proposals to increase imports from Hydro Quebec to Central New England (e.g. Northern Pass), we assume 1,000 MW of HQ-CMA in 2020.

AESC 2011 also assumes a 1,000 MW increase the transmission capacity between Maine and the rest of New England, effective 2014. This assumption is based in part on estimates of the transfer effects in the Maine Power Reliability Plan (MPRP). Additional transmission is also necessary to allow new renewable resources access to load. Modeling results indicate if new capacity is not added, then energy prices in Maine fall substantially below the rest of New England which provides a strong economic argument for increased interties.

2.3.2.4. Generating Unit Retirements

Various policies, economic and environmental regulations will lead to the retirement of various New England generating units. The specific units we assume that will be retired are presented in . AESC 2011 treats retirements as occurring on January 1 of the relevant year. AESC 2011 l retires about 10 MW of old gas turbines annually after 2012.

Exhibit 2-8: Unit Retirements for Energy Modeling

Retirement Date	Unit Type	Station Name	Unit ID	Summer CELT Capacity (MW)
10/1/2010	ST	Somerset	6	108.5
10/1/2010	GT	Somerset	Jet 2	21.8
10/1/2010	GT	St Albans	1 & 2	2.2
1/1/2013	ST	Salem Harbor	1	83.9
1/1/2013	ST	Salem Harbor	2	80.5
1/1/2013	ST	Bridgeport	2	130.5
1/1/2013	ST	Holyoke Cabot	6 & 8	19.3
1/1/2013	NUC	Vermont Yankee		604.3
1/1/2015	ST	Norwalk Harbor	1	162.0
1/1/2015	ST	Norwalk Harbor	2	168.0
1/1/2016	ST	Salem Harbor	3	149.9
1/1/2016	ST	Salem Harbor	4	436.5
1/1/2016	ST	Cleary	8	26.0
1/1/2016	ST	Montville	6	407.4
1/1/2016	ST	Middletown	4	400.0
1/1/2016	ST	Cleary	8	26.0
1/1/2018	ST	Wyman	1	52.0
1/1/2018	ST	Wyman	2	51.0
1/1/2020	ST	Mount Tom		143.4

Notes
ST Steam Turbine
GT Gas Turbine
NUC Nuclear

The basis for these assumptions is presented below.

Vermont Yankee

The AESC 2011 Reference Case assumes Vermont Yankee retires in 2013.

The NRC has granted Vermont Yankee a 20-year license extension, but the plant also requires state permission to operate past March 2012. The Vermont Senate voted 26–4 in February 2010 to deny that extension, in part due to tritium leaks, a cooling-tower collapse, and errors found in the owner's testimony before the Legislature. Since then, the plant has experienced additional tritium leaks. Vermont Yankee is of the same vintage (early 1970s) and design (Mark I boiling-water reactor) as the Fukushima Daiishi reactors that suffered fuel melting, explosions, radiation releases, and draining of the spent-fuel pools in March 2011. The Vermont Legislature appears unlikely to reverse its decision under these circumstances.

Environmentally-Driven Retirements of Coal Plants

Eight coal plants (consisting of 15 units) are operating in New England. The AESC 2011 Reference Case assumes five of those units will retire over the Study period.

- **Somerset 6** (Massachusetts) has shut down and we treat it as retired. Somerset has not cleared in any of the FCAs held to date.
- **Salem Harbor 1–3** (Massachusetts) has submitted high bids for the third and fourth FCA. Units 1 and 2 were allowed to delist, but Unit 3 has been required to stay on line for reliability, at a price of $5.22/kW-month. Salem filed permanent delist bids for all four units in FCA 5, which was rejected, and then filed a non-price bid. Salem has no baghouse, SCR or scrubber, and is subject to 136(b) requirements. All indications are that the owner intends to retire the plant. We treat Units 1 and 2 as being retired in June 2012, and Units 3 being retired in June 2015, assuming that transmission upgrades will eliminate the reliability need for the plant.[40]
- **Mt. Tom** (Massachusetts) has installed SCR and a baghouse, but is very small. We assume this unit retires in 2020.

Our understanding of the environmental regulatory status of the remaining plants is as follows:

- **Thames A and B** (CT) is a fluidized-bed plant built in the late 1980s, with relatively low emissions. We expect this plant to operate throughout the modeling period. However, the plant is currently in bankruptcy, allegedly due to sales contracts for steam (with Smurfit Container) and electricity (with CL&P) that are now below costs. The plant's owner asserts that its "variable costs" have risen from $37.09/MWh in 2000 to $53.81/MWh in

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[40] Dominion, the owner of Salem Harbor, has announced that it will retire Units 3 and 4 in June 2014.

2009, largely due to: increased (a) cost of coal, (b) transportation costs and (c) environmental compliance costs affecting ash disposal and the need to purchase $C0_2$ allowances in compliance with the RGGI." (Declaration of Brian Chatlosh in Support of First Day Motions, February 1, 2011, p. 7) It is not clear whether "variable costs" are limited to costs that vary with energy output. We expect that, as a result of the bankruptcy, Thames will no longer be dispatched as a must-run plant and instead will operate as an intermediate plant We expect this plant to operate throughout the modeling period. (Thames did not clear in FCA 5.)

- **Bridgeport 3** (CT) has relatively low NO_x emission rates (0.14 lb/MMBtu in 2010) for a coal plant and a baghouse to control particulate and mercury emissions, but does not have a scrubber or post-combustion NO_x controls. The plant burns very-low-sulfur coal. Bridgeport 3 has been bidding into the ISO energy markets at prices in the range of $40–$50/MWh, and bidding 130 MW (its minimum load level) as must-take energy in the summer, presumably to minimize NO_x emissions. The unit operated at capacity factors up to the 80% range a few years ago but in only the 30–40% range in 2009 and 2010, presumably due to lower gas prices (and hence lower electricity energy prices) and higher coal prices. It is also subject to 136(b) cooling-water restrictions. While Bridgeport 3 is highly vulnerable and its future is uncertain, we assume that it continues operating in the Reference Case.

- **Brayton 1–3** (Massachusetts) appears committed to making the improvements necessary to meet all pending emission and water-use requirements and stay in operation. The plant has installed, or is installing, SCR, scrubbers, and cooling towers. We assume that Brayton will continue operating. The same is true for the Brayton 4 oil unit.

- **Merrimack 1 and 2** (New Hampshire) have a scrubber and SCR, and are owned by a vertically-integrated utility, with a lower cost of capital than merchant generators . We expect that the plant will continue to operate.

- **Schiller 4 and 6** (New Hampshire) are small (48 MW) and old (1952 and 1957 in-service date), with no major pollution controls other than SNCR and precipitators. In 2010, the units' NOx emissions were nearly 0.3 lb/MMBtu. New Hampshire will likely be excluded from the Clean Air Transport Rule. We have not identified any particular factor that would lead to the shutdown of these units, but given their age and the potential for additional environmental controls (such as to minimize haze in Acadia National Park), they should be considered to be vulnerable.

Environmentally Driven Retirements of Oil- and Oil-and-Gas-Fired Steam Plants

We have less complete information on the old steam plants fired by oil and/or gas. None of these plants are likely to be able to support the cost of major emissions controls. We do not have the type of evidence of owner commitment to continuing operation of these units as we do for Brayton, Bridgeport 3, Mt. Tom, and Merrimack.

The AESC 2011 Reference Case assumes the following units will retire over the Study period:

- **Bridgeport Harbor 2** has delisted for FCA 4 and FCA 5. It has high NOx emissions, no special emissions controls, particularly low capacity factors, and 136(b) exposure. We assume it is retired in June 2013.
- **Salem 4** burns only oil, and its owner has been attempting to delist it from the FCAs, along with the coal units. We assume this unit retires in June 2015, along with Unit 3.
- **Norwalk Harbor** (Connecticut) has reported very high O&M costs (both under regulation and in its RMR cost claim). While it has SNCR installed, and hence relatively low emissions, it is also subject to 136(b) restrictions. These units have cleared through FCA 4 (except for a play for higher RMR payments in FCA 1). We assume that units 1 and 2 will retire in 2015.
- **Middletown 4** and **Montville 6** (Connecticut) are relatively large (400 MW) and modern (early 1970s), and have moderate NOx emission rates, but burn only oil, operate at low capacity factors, and have particularly high heat rates. We assume that they will be retired in 2016.
- **Cleary 8** (Massachusetts) burns oil, is only 26 MW, and has the highest NOx emission rates in New England. We assume that the unit will retire in 2016.

The information we have regarding the remaining major units in this category is summarized below:

- **New Haven Harbor** (Connecticut) is dual-fueled (although not as flexible as some other dual-fuel units), with moderate NOx emissions and capacity factors.
- **Middletown 2 and 3** (Connecticut) have relatively low NOx emissions, dual-fuel capability, and high capacity factors for oil/gas units.
- **Montville 5** (Connecticut) has very low NOx emissions, dual-fuel capability, and relatively high capacity factors. The owner has proposed converting the unit to co-fire biomass.

- **Canal 1** (Massachusetts) has installed selective catalytic reduction (SCR) and operates with very low NOx emissions, while **Canal 2** has installed selective non-catalytic reduction (SNCR) and has moderate emissions. Unit 2 is dual-fueled. The units' capacity factors have been variable, from low to moderate. They are subject to continuing proceeding with EPA regarding compliance with 136(b) requirements.
- **Wyman 1–4** (Maine) run on higher-sulfur (0.72 percent sulfur by weight) and hence less expensive fuel than other oil plants in New England (generally 0.5 percent in Massachusetts and 0.3 percent in Connecticut), and hence operate more often, even though they are in Maine, the zone with the lowest market energy and capacity prices.[41] Other than a requirement to switch to 0.5 percent sulfur oil in 2018, Wyman does not appear to face any environmental challenges. Maine, like New Hampshire, has not been subject to as stringent NOx controls as the southern New England. The Wyman units are subject to 136(b). ISO-NE determined in May 2009 that both Units 1 & 2 are needed for reliability until completion of transmission upgrades in southern Maine. These units have not filed above-market delist bids, suggesting that their forward-going costs are less than the FCM prices through FCA 4, when the price paid to generation in Maine fell to $2.336/kW-month, or $28/kW-year.[42] The completion of the Maine Power Reliability Project will apparently eliminate the reliability need for Wyman 1 & 2, and we assume the retirement of those units in June 2014.
- **West Springfield 3** (Massachusetts) burns both oil and gas, has moderately low NOx emissions and relatively high capacity factors and does not appear to face any specific environmental challenges. (This unit did not clear in FCA 5.)
- **Brayton 4** is dual-fueled and has low NOx emissions, and will share a cooling tower with the coal plants, but has operated at low capacity factors.

[41] This plant is also sometimes referred to as Yarmouth 1–4.

[42] The Wyman owner has asserted that "Units No. 1 and 2 are not expected to realize any energy revenues in the foreseeable future. Additionally, a bleak capacity revenue outlook makes it unlikely that the subject units will recover their full operations and maintenance costs, and capital expenditures. Since it is not economically feasible to maintain the units, FPL Energy is seriously contemplating retiring Units No. 1 and 2 in the near future." (Request for Determination of Need for System Reliability and Consideration of RMR Cost-of-Service Agreement for Wyman Units No. 1 and 2; December 11, 2008) Despite these warnings, Wyman 1 & 2 have continued clearing with only market capacity prices.

- **Newington** (New Hampshire) burns both oil and gas, has relatively high capacity factors, has been allowed to burn higher-sulfur oil than most New England plants, and does not appear to face any special environmental challenges.
- **Mystic 7** (Massachusetts) burns both oil and gas, has very low NO_x emissions and moderate capacity factors, and does not appear to face any environmental challenges.

Economic Shutdown and Retirements

The economic viability of old (pre-1980) New England combustion turbines as well as old oil- and gas-fired steam plants is strongly influenced by capacity-market prices, which is their primary source of revenue. Starting in June 2016, the extended floor on the FCM price is scheduled to end, and (barring a further extension of the floor) the capacity price in New England could fall dramatically for several years if no existing resources delist (that is, withdraw from the auction either in advance or as the price falls).).

In FCA 4, the floor price of $2.95/kWh ($2.84/kW-month in 2011$) was reached with 4,563 MW of excess capacity

AESC 2011 assumes that approximately 1% of pre-1980 combustion turbines (roughly 10 MW, or a unit every year or two) will retire annually through the modeling period. We assume that the Somerset Jet has been permanently retired; it has not cleared in any of the capacity auctions. listed the specific retirements AESC 2011e assumes, including the retirement of two small Holyoke municipal units that have delisted in FCA4.

2.3.2.5. Generating Unit Additions

Appendix C provides specific information about the resource types that qualify for each state program and the future RPS requirements levels for each state.

As discussed in Section 2.2.2.4, specific renewable energy resources will be based in the near-term on generation in the interconnection queues and other sources in the near-term, and based on a supply curve analysis in the longer term.

The operating characteristics of renewable generation units will be reasonably consistent between the Market Analytics modeling inputs and the SEA analysis. Inputs into the model will be verified by SEA to ensure consistency.

Planned Additions & Uprates

The AESC 2011 forecast of non-renewable generator additions is based on capacity that has cleared in FCA 4 and filings with the Connecticut DPUC for projects under contract with the Connecticut utilities. New entry assumptions are shown in the exhibit below. These planned additions are highly likely to reach commercial operation. Further additions will be treated as generic units.

Exhibit 2-9: Planned Non-Renewable Additions (in Addition to ISO-NE 2011)

	Unit Type	Fuel Type	Summer Net MW	State	Projected Commercial Operation Date
New Haven	GT	NG, DFO	133	Conn.	6/1/2012
Ansonia Generating	GT	NG	60	Conn.	6/1/2010

This tabulation does not include the fuel cell projects under contract in the Connecticut DPUC Project 150 process, since these are treated as renewable generation for Connecticut purposes.

Generic Additions

In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions will be added as needed to the model. These, generic additions will be comprised of a 50/50 mix of capacity from gas/oil fired 490 MW combined-cycle and 180 MW combustion turbines. No coal or nuclear units will be added.

Generic additions will be added to meet the New England Installed Capacity Requirement in conjunction with our analysis of the forward capacity market. New resources will be dispersed geographically based on a combination of zonal need and historical zonal capacity surplus/deficit patterns. Maine's surplus of capacity, low energy prices and export constraints will tend to suppress development of new generic capacity in that zone. The locational markets for energy and forward reserves will tend to provide incentives to build new generation in import-constrained zones, principally Connecticut.

2.3.2.6. Generic Generating Unit Operating Characteristics

Thermal Units

Market Analytics represents generation units in detail, in order to accurately simulate their operational characteristics and therefore project realistic hourly dispatch and prices. These characteristics include:

- Unit type (steam-cycle, combined-cycle, simple-cycle, cogeneration, etc.)
- Heat rate values and curve
- Seasonal capacity ratings (maximum and minimum)

- Variable operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs
- Ramp rates
- Emission rates (SO_2, NO_x, CO_2, and mercury)

The Market Analytics data is based on a variety of reliable public sources such as EIA reports and FERC filings, although some sources are proprietary.[43]

Exhibit 2-10: Characteristics of Market Analytics Generic Unit Additions

Characteristics	**NG CC**	**NG CT**
Typical Size (MW)	490	180
Heat Rate (Btu/kWh)	6,800	10,500
Variable O&M costs (2010 dollars per MWh)	$2.15	$3.75
Availability	90.4%	92.3%
NO_x (lb/MMBtu)	0.01	0.03
SO_2 (lb/MMBtu)	0	0
CO_2 (lb/MMBtu)	120	120
Notes NG CC Natural Gas Combined Cycle NG CT Natural Gas Combustion Turbine		

Fuel Prices

Prices for electric generation fuels are detailed in Chapter 3 and Chapter 5.

Nuclear Units

There are four nuclear plants and five nuclear units in New England (Millstone 2 and 3, Pilgrim, Seabrook, and Vermont Yankee) with a combined summer capacity of 4,541 MW, representing approximately 15 percent of the total New England capacity.

[43] Specific details about the Market Analytics Model inputs can be requested and provided under appropriate confidentiality agreements.

Exhibit 2-11: New England Nuclear Unit Capacity and License Expirations

Unit	AESC Zone	Capacity (MW)[a]	License-Expiration Year[b]
Millstone 2	CT	876 [a]	2035 [b]
Millstone 3	CT	1,225 [a]	2045 [b]
Pilgrim	SEMA	677 [a]	2012 [b]
Seabrook	NH	1,247 [a]	2017 [b]
Vermont Yankee	VT	604 [a]	2012 [b]
[a]CELT 2011 Summer capability [b]U.S. Nuclear Regulatory Commission			

Of the five operating nuclear units in New England, the Nuclear Regulatory Commission (NRC) has relicensed Millstone 2 and 3, along with 60 other reactors outside New England, without denying a single extension). Based on this track record and the lack of evidence that suggests that the NRC would deny the license renewals for any of these plants, we assume that all of the nuclear plants in New England will receive NRC licenses to operate for another 20 years, through the entire modeling period.

Seabrook filed a license-extension application in June 2010, which is nearly certain to be granted.

As discussed, the NRC recently granted Vermont Yankee a 20-year license extension, but the plant also requires state permission to operate past March 2012.

Pilgrim's operating license expires in June 2012. Its design and vintage is very similar to that of Vermont Yankee and Fukushima Daiishi, and it is also located on the coast. Serious earthquakes along the Massachusetts coast are very rare, but not unknown. Pilgrim is thus among the US nuclear units most likely to be affected by increased safety requirements following the Fukushima disaster, either as part of an extended relicensing review or subsequently. Many such measures (hardening of spent-fuel pools and back-up power supply, transferring spent fuel to dry casks, building higher seawalls) would have little effect on Pilgrim's power output. Nor are those measures likely to result in economic retirement of the plant. On the other hand, if the NRC were to require fundamental design changes in the Mark I reactors, Pilgrim would be likely to retire. The NRC has rarely required such major modifications to licensed reactors. We thus assume that Pilgrim will continue operating.

The licensed capacity of all five New England nuclear units has been increased, most recently by an, 80 MW increase in Millstone 3 capacity in 2010.

Conventional Hydro and Pumped Storage Unit Characteristics

The Market Analytics database will be used as the primary source all hydro unit information. Conventional reservoir and run-of-river hydro resources are considered a "fixed energy" station or contract in the model. Like thermal stations, these stations have a maximum and minimum generating capacity, but they also have a fixed amount of energy available within a specified time (i.e., a week or a month). Hydro stations operate generally on peak in a manner that levels the load shape served by other stations. Hydro stations are scheduled one at a time over the horizon of a week, subject to hourly constraints for minimum and maximum generation, and weekly constraints for ramp rates and total energy. Although the load shape they intend to level is the overall system load, a hydro station can be scheduled against the load of a specified transmission area or control area.

Pumped-storage type resources (with exchange contracts) have slightly different modeling requirements, typically involving a series of reservoirs used to release water for energy generation during peak load periods and pump water back uphill during off-peak times when energy demand and price is lower. The water (fuel) of pumped hydro generation is valued at the cost of pumping, allowing for net plant efficiency. Hourly reservoir levels are computed and a look-ahead is employed to prevent drawing the reservoir below the level where pumping space allows refilling to the desired level before the beginning of the next peak period.

2.3.2.7. Demand Resources

Demand resources will be included in the model consistent with the ISO-NE 2008 RSP and the FCA results (through FCA-4). These resources will be modeled as generating units that act as load reduction resources that are committed only if all other available generating resources are operating at full capacity and load is about to be lost. These resources do not set the marginal clearing price.

2.3.2.8. Emission allowance costs

The proposed inputs for emission allowances costs are summarized in Exhibit 2-3, above.

2.3.3. Model Calibration

Since a key objective of this study is the calculation of avoided electric energy costs, we took steps to ensure that the model is forecasting energy market prices accurately. The calibration approach we use is to compare the prices forecast by the model to electric energy historic and futures prices at the ISO-NE hub. The ability to make this comparison is complicated by the SOW requirement for the model to forecast prices assuming no continuation of energy-efficiency activities, i.e. no "new" reductions. The complication is that the electric-energy future prices will reflect the expectations of buyers and sellers in the actual market, who are likely assuming continuation if not escalation of existing efficiency programs.

Consequently, we model the current market situation with the energy efficiency resources that cleared in the 2010 forward capacity auctions. We then make appropriate model adjustments (e.g. bidding strategies, etc.) to reasonably match the electric-energy historic and futures prices at the ISO-NE hub over the three years (2010–2012).

2.4. Wholesale Electric Capacity Market Simulation Model and Inputs

2.4.1. Description of Forward Capacity Market Simulation Model

AESC 2011 uses a spreadsheet model to develop FCM auction prices for power-years from June 2014 onward. The major input assumptions regarding the forecasts of peak load and available capacity in each power-year are coordinated with, and consistent with, the input assumptions used in the Market Analytics energy market simulation model.

The major assumptions used to simulate the future operation of the FCM are listed below*:*

- The FCM remains as currently structured.
- Installed capacity requirements (including the Hydro Quebec capacity credits), estimated from the peak loads in the 2011 CELT and the required reserve margins (ICR ÷ peak load–1) in the 2010 RSP. Both are extrapolated through the analysis period. Growth in Maine requirements is met by some of the 427 MW of Maine capacity in excess of Maine’s requirements and export capability. Since the required reserve margin rises steadily over time in the 2010 RSP, we will extend that trend.
- Resources generally continue to bid FCM capacity in a manner similar to their bidding in FCA 4. Most existing resources continue to bid in as a “price-taker,” at or below the minimum FCM price. Units built by municipal utilities or under contract to the Connecticut utilities bid as price-takers.
- Generators facing large costs for maintenance, equipment replacement or environmental compliance will submit bids high enough to cover their costs. If the FCM price falls below that level, the generators will not clear in the FCA and will be free to shut down.
- In the event of a major drop in the New England capacity price, a large amount of capacity now imported to New England from Quebec and New York (including imports from Quebec through New York) could withdraw

from the New England market, and instead sell capacity into the markets in New York or PJM. Some domestic New England capacity could probably also delist to sell capacity out of the region, while continuing to be available to serve energy loads in New England. It is not clear how much more appealing other capacity markets will be. Capacity prices in upstate New York have been even lower than in New England. In 2010 and 2011, the capacity price averaged about $1.15/kW-month. These low prices may be the result of capacity additions to meet requirements in New York City (which increase total statewide capacity and reduce upstate prices), plus additions of renewables. The clearing price for capacity imports to PJM is even lower, at about $0.84/kW-month. Lower capacity prices would probably cause the providers of some of the existing demand-response resources that the capacity revenues are not worth the cost and inconvenience of reducing load, resulting in their delisting.

- FCA 4 cleared at the floor price with over 4,000 MW of excess capacity. However, ISO NE has classified 1,527 MW of the cleared capacity in FCA4 as being “out of market” (OOM), meaning that it could not be supported by market revenues alone. OOM resources are not allowed to set the market-clearing capacity price.
- Once the existing surplus no longer exists, due to retirements and load growth, FCM prices will be determined by the price of new peaking units under long-term contracts, net of a conservative estimate of energy profits and operating-reserve revenues. We assume that one or more states or utilities will intervene to ensure that new generation is built without waiting for the price becoming high enough to motivate merchant generators. Capacity will be added preferentially in the areas with the lowest reserves and the highest market prices, gradually equalizing reserves across the region. Connecticut is most likely to have energy and possibly FCM prices higher than average, and Maine is the zone most likely to energy and possibly effective FCM prices below average.
- Assumptions regarding FCM prices will be based upon the slope of the supply curve. We have detailed supply curves above $2.95/kW-month from the published results of FCA 4. Below $2.95/kW-month, we assume the average slope from the bottom of FCA 4 supply curve.

AESC 2011 uses these assumptions to estimate FCM prices for power years from June 2014 onward. We start with the capacity that cleared in FCA 4, adding the capacity and subtracting the retirements described in Section 2.2.2.3 above. The resulting capacity available to bid in each power is compared to the future ICR. In both retirements and load growth, we net Maine changes against the Maine-specific surplus.

2.4.2. Values for Input Assumptions to FCM Model

The underlying driver to the Forward Capacity Auctions is the Installed Capacity Requirement (ICR). The ICR is calculated by applying a percentage reserve requirement to the CELT peak load forecast. The owners of capacity entitlements on the Hydro Quebec Phase I/II interconnection (the New England utilities that pay for the HVDC transmission link) are price-takers, and the auction is actually for the remaining capacity need, the Net Installed Capacity Requirement (NICR). Holders of Hydro Quebec Interconnect Certificates (HQICC) receive the resulting auction price although they do not participate in the auction itself.

Our analysis is based on the ISO's projections of NICR through 2019/20 published in the 2010 Regional System Plan. We will project the ICR based on the trend in the ISO's forecasts of load and reserve requirements.

Based on the historical relationship between the price in each round of the auctions and the amount of capacity offered at that price, we estimate that, once the capacity price is no longer bound by the floor price in FCA7, the capacity price will rise by about $0.003/kW-month for each addition MW required above the resources that cleared in FCA 4.

2.5. External Costs Avoided

The calculation of avoided electricity costs incorporate some costs that that are not internalized, or reflected, in our projections of wholesale market prices for energy and capacity. We address the following components:

- Reliability contracts;
- Renewable Energy Credit (REC) purchases;
- Demand-reduction-induced price effects (DRIPE) in the wholesale energy and capacity markets; and
- Environmental externalities.

These avoided electricity-supply costs do not include several components of wholesale power costs that we consider to be largely or entirely unavoidable through Demand Side Management (DSM). These components include the locational forward reserve market, real-time operating reserves, automatic generation control (also called regulation), uplift, and the reliability contracts with particular generators.

2.5.1. Reliability Contracts

In the past, ISO-NE granted special reliability-must-run (RMR) contracts to a set of power plants. The ISO determined that these plants needed to continue to operate in order to ensure reliability, typically because of their unique location, but that they would not be economically viable based solely upon the revenues from then-current market prices. The prices in the RMR contracts covered the plants' variable production costs (e.g., operations and maintenance) as well as their fixed costs (mostly capital).

All of the RMR contracts have expired, the last of them on June 1 2010. A few units have received special reliability contracts in connection with transmission constraints in the FCAs:

- Norwalk Harbor 1 is covered by a contract at $1.75/kW-month above the market-clearing price of $4.50/kw-month in 2010/11. Lower loads and increased generation in Connecticut allowed the ISO to delist Norwalk Harbor 2, which had originally been offered a reliability contract, as well.
- Salem 3 and 4 will likely be paid $5.33/kW month in 2012/13 and $5.005/kW-month in 2013/14. In FCA4, the ISO found that 460 MW of Salem capacity was required for reliability; since Unit 4 is 437 MW, a load reduction of 23 MW (or a smaller amount, combined with other changes) could eliminate the need for Unit 3. The ISO also reported that the need for Salem had been reduced, between FCA 3 and FCA4, by an 82 MW reduction in load forecast for portions of the Boston area. (FCA results filing, August 30, 2010)
- Vermont Yankee will receive a reliability contract for 2013/14; the price may be as high as $3.933, but the price has not been reviewed by the ISO or FERC. Since Vermont Yankee is unlikely to be licensed to operate past March 2012, that contract is unlikely to have any effect.

It thus appears that some of the costs of reliability contracts have been avoidable. Accelerated energy efficiency in the NEMA area, along with distributed generation and transmission improvements, may avoid the cost of one of the Salem units in 2012–2014 and beyond. Additional reliability contracts may have been avoided by load reductions that have already occurred, or are reflected in the demand resources bid into the FCAs. Continuing reductions may avoid reliability contracts for other generators that may seek to delist in future years.

2.5.2. Other Wholesale-Load-Cost Components

In addition to the locational marginal energy prices and capacity prices, the ISO-NE monthly "Wholesale Load Cost Report" includes the following cost components:

- First-Contingency Net Commitment Period Compensation (NCPC),
- Second-Contingency NCPC,
- Regulation (automatic generator control),
- Forward Reserves,
- Real-Time Reserves,
- Inadvertent Energy,
- Marginal Loss Revenue Fund,
- Auction Revenue Rights revenues,
- ISO Tariff Schedule 2 Expenses,
- ISO Tariff Schedule 3 Expenses,
- NEPOOL Expenses.

These cost components are described in more detail in the Wholesale Load Cost Reports, available from the ISO's web site, www.isone.com.

None of these components vary clearly enough with the level of load to warrant inclusion in the avoided-cost computation. More specifically:

- The NCPC costs are compensation to generators that are comply with ISO instructions to warm up their boilers, ramp up to operating levels, remain available for dispatch, possibly generate some energy, and then shut down without earning enough energy- or reserve-market revenue to cover their bid costs. Older boiler plants may take many hours to reach full load and have minimum run-times and shut-down periods, requiring plants to continue running at minimum levels overnight. Smaller loads would tend to reduce the need for bringing these plants into warm reserve, thus reducing NCPC costs. On the other hand, lower energy prices would tend to increase the net compensation due to these units when they were required, since they would earn less when they actually operated. Hence, while energy efficiency may affect NCPC costs, the direction and magnitude of the effects are not clear.

- Regulation costs are associated with units that follow variations in load and supply in the range of seconds to a few minutes. Reduced load due to efficiency is likely to result in reduced variation in load (in megawatts per minute), reducing regulation costs. On the other hand, some controls may increase regulation costs, if end-use equipment responds more quickly to changing ambient conditions. Overall, energy efficiency programs will probably reduce regulation costs, but we cannot estimate the magnitude of the effect.

- Forward and real-time reserve requirements should decrease slightly with energy efficiency, for two reasons. First, lower load will tend to leave more available capacity on transmission lines, which will tend to reduce the need for local reserves. (This factor could be important in the Connecticut Locational Forward Reserve Market, as well as in other areas in the real-time market.) Second, a portion of real-time reserves are priced to recover forgone energy for units that remain in reserve; lower energy prices will tend to depress reserve prices. We expect that these effects would be small and difficult to measure.
- Inadvertent Energy exchanges with other system operators (NY ISO, Hydro Quebec, and New Brunswick) are small and probably not affected by energy efficiency.
- The Marginal Loss Revenue Fund returns to load the difference between marginal losses included in locational energy prices and the average losses actually experienced over the pool transmission facilities. That fund is—by definition—generated by infra-marginal usage, and will not be affected by reduction of loads at the margin.
- Auction Revenue Right revenues are generated by the sale of Financial Transmission Rights (FTR), to return to load the value of transfers on the ISO transmission facilities. To the extent that efficiency programs reduce energy congestion, the value of these rights will tend to decrease.
- Expenses (ISO Tariff Schedules 2 and 3 and NEPOOL) are largely fixed for the pool as a whole, although a portion of the ISO tariffs are recovered on a per-MWh basis. Some of the ISO costs may decrease slightly as energy loads decline, if that leads to a reduction in the number of energy transactions, dispatch decisions, and other ISO actions required. Any such effect is likely to be small and slow of occur, and energy-efficiency programs add their own costs in load forecasting, resource-adequacy planning, and operation of the forward capacity market.

2.5.3. Cost of Compliance with Renewable Portfolio Standards

Five out of the six New England states have adopted renewable portfolio standards. See Chapter 6 and Appendix C for a detailed summary and description. In all RPS markets, LSEs demonstrate compliance through the acquisition and retirement of NEPOOL Generation Information System certificates, which are also more casually referred to as RECs. Some states have also implemented additional requirements that specific percentages of energy be provided by unconventional non-renewable or efficiency resources. Two examples of such alternative requirements are the Massachusetts Alternative Portfolio Standard (which includes combined heat and power, flywheel storage, coal gasification, and efficient steam technologies) and the Connecticut Class III RPS requirement (which includes CHP, conservation and load management, and waste heat or pressure recovery).

AESC 2011 assumes LSEs will comply fully with established RPS requirements each year – either by securing RECs or by making Alternative Compliance Payments. For ease of presentation, this discussion generally refers to all of these requirements as RPS requirements, which must be met with RECs, even though some of the resources are not renewable.

Our estimate of avoided costs includes an estimate of the REC costs that reduction in load will enable an LSE to avoid. Reduction in load due to DSM will reduce the RPS requirement of the LSE and therefore reduce the cost they incur to comply with that requirements. That RPS compliance cost is equal to the price of renewable energy in excess of market prices, i.e., the REC price, multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

$$\text{Avoided RPS cost} = \text{REC price} \times \text{RPS percentage}$$

For example, in a year in which REC prices are at $30/MWh (or 3¢/kWh) and the RPS percentage was 10%, the avoided RPS cost to a retail customer would be $0.30 cents/kWh. We will calculate the RPS compliance costs that retail customers in each state avoid through reductions in their energy usage in each year for each major applicable RPS tier as follows:

$$(\text{REC Price}_n \times \text{RPS }\%_n)/(1-L)$$

Where:

n = the RPS tier

L = the load-weighted average loss rate from ISO wholesale load accounts to retail meters

We forecast annual REC prices for three major RPS tiers. These are new renewables (primarily Class I), all New Hampshire Class II solar, and all other renewables.

The major drivers of new renewable energy are the new-renewables RPS tiers. These include Class I in Massachusetts, Maine, Connecticut, and New Hampshire; the “New” RPS requirement in Rhode Island, and the expected Vermont RPS as assumed to be in place by 2013. For 2011 and 2012 we rely upon recent broker quotes to estimate the market prices at which RECs are transacted. REC markets in New England continue to suffer from a lack of depth, liquidity, and price visibility. Broker quotes for RECs represent the best visibility into the market's view of current spot prices. However, since RPS compliance must be substantiated annually, and actual REC transactions occur sporadically throughout the year, the actual weighted average annual price at which RECs are transacted will not necessarily correspond to the straight average of broker quotes over time. Broker quotes for RECs may span several months with few changes and no actual transactions (being represented by offers to buy or sell), and at other times may represent a significant volume of actual transactions. As a result, care should be taken to filter such data for reasonableness.

Exhibit 2-12 below provides the type of REC prices we will use to characterize the near-term REC market prices.[44]

Exhibit 2-12: Annual Average REC and APS Prices 2010, and January–March 2011 (Dollars per MWh)

		2010	2011
Conn.	Class I	$13.50	$13.50
	Class II	$0.50	$0.90
	Class III	$11.25	$10.00
Mass.	Class I	$15.00	$14.95
	Class II renewable	$23.75	$23.00
	Class II waste-energy	$4.00	$5.25
	Class APS	*$19.00*	*$19.00*
R.I.	New	$16.00	$15.25
	Existing	$0.75	$0.75
Maine	Class I	$7.75	$9.00
	Class II	$0.18	$0.18
N.H.	Class I	$13.50	$15.50
	Class II solar	*$25.00*	*$25.00*
	Class III	$21.50	$18.75
	Class IV	*Not Available*	$24.50
Data from confidential REC brokers quotations compiled by Sustainable Energy Advantage, LLC			

[44]This table was developed from a representative sampling of REC brokers quotes, which is comprised of both consummated transactions and bid-ask spreads in periods where transactions were not reported.

The AESC 2011 estimates of Class 1 REC prices in the longer-term (after 2012) are based on analysis of the near-term supply and demand balance, banking limits and observed practices, and the cost of entry of new renewable energy resources in each applicable year. That analysis relies on SEA's renewable energy supply curve model to determine the marginal (or market-clearing) resource in each year, through 2026. The supply curve takes various resource potential studies as inputs, calculated the cost of energy for each block and then stacks the supply resources from lowest to highest cost of energy – taking into account recent estimates of equipment, operating and financing costs. The intersection between supply and demand determines the marginal resource. REC prices are estimated based on the difference between the levelized cost for the marginal renewable resource and the resource's commodity market value based on our reference-case forecast of wholesale electric-energy-market prices. A more detailed explanation of the supply curve analysis is provided in Chapter 6.

We will forecast REC prices for the remaining two tiers as follows:

- For New Hampshire Class II (solar) REC prices are estimated at the lesser of (1) the alternative compliance payment rate and (2) the difference between a levelized cost of energy estimate for solar and our production-weighted reference-case forecast of wholesale electric-energy-market prices.
- For all other RPS tiers we will escalate recent broker-derived prices at inflation. The exception to this methodology will be for RPS classes focused on existing supply but for which such existing supply has not been certified by the applicable RPS authority in a quantity sufficient to meet demand. Near-term REC prices for such classes will be estimated based on current broker quotes and the applicable ACP. REC prices will be assumed to trend toward values which reflect a market in equilibrium or modest surplus over time, as existing generators become certified and participate in the program.

2.5.4. Demand Reduction Induced Price Effects – Methodology and Assumptions

AESC 2011 provides estimates of the effect of reductions in demand and energy from DSM programs on wholesale market prices for capacity and energy in Chapter 6. Our general approach is described below.

2.5.4.1. Wholesale Capacity Market Effects

AESC 2011 estimates capacity DRIPE using our estimates of capacity price in each FCA as a function of the ISO's net installed capacity requirements and available resources. From June 2016 onward, we assume that the FCM price will be set by the market, rather than ISO-NE setting floor prices. From that point onward, FCM prices will be determined by the prices at which generators choose to delist. (By delisting, generators in New England are able to sell into another market such as New York, or to shut down.) We use the model described above in Section 2.4.

Our analysis includes the phase-out of capacity DRIPE over time, in response to factors similar to those affecting energy DRIPE.

2.5.4.2. Wholesale Energy Market Effects

AESC 2011 estimates the magnitude of wholesale energy market DRIPE by year by conducting a set of regressions of historical zonal hourly market prices against zonal and regional load similar to the process conducted in AESC 2007 and AESC 2009.

We estimate the duration of energy DRIPE after estimating the magnitude. We estimate the phase-out of energy DRIPE based upon the assumption that the effect of reductions from efficiency programs on energy market prices will not last indefinitely. Instead, over time, customers will respond to lower energy prices by using somewhat more energy, the market will respond to sustained lower loads, for example by retiring existing generating capacity or delaying new supply and demand-response resources, and lower loads will tend to result in lower acquisition mandates under renewable and other alternative-energy standards.[45] While the shutdown of peaking units (gas turbines and older steam units) has little effect on market energy prices, the shutdown of coal plants or the delay in construction of new renewable or combined-cycle plants may have larger effects. We develop a phase-out of DRIPE effects consistent with the load-related retirements above in Section 2.2.2.

Our analysis of the phase-out of DRIPE effects is informed by a review of the literature on the effect of load reductions (or alternatively, load increases or addition of other resources) on market prices in competitive electricity markets is presented in Chapter 6.

Finally, in order to develop the energy DRIPE to be used in avoided costs we have phased in its impact based upon the portion of retail electricity power that reflects wholesale market prices at any point in time. This adjustment is required because the actual percentage of electricity supply being acquired at prices reflecting current wholesale market prices varies among the states, among the utilities within

[45] Simple delisting of generators in the forward-capacity markets, such as to permit exports, does not directly change their operation in the energy markets.

some states, between municipal utilities and independently owned utilities (IOUs), and between customers on standard utility offer (standard service, default service, last-resort service, etc.) and those served by competitive suppliers.

2.5.4.3. Carbon Mitigation Value

Our approach to quantifying the reduction in physical emissions d**ue** to energy efficiency is as follows:

- Identify the marginal unit in each hour in each transmission area from our energy model;
- Draw the heat rates, fuel sources, and emission rates for NO_x andCO_2, of those marginal units from the database of input assumptions used in our Market Analytics simulation;
- Calculate the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of lbs/MWh and lbs/kW. We multiply the quantity of fuel each marginal unit burned by the corresponding emission rate for each pollutant for that type of unit and fuel.

Our recommended dollar values to use for relevant avoided pollutant emissions are summarized in Exhibit 2-3.

Externalities are values that are not reflected in market prices. AESC 2011 identifies CO_2 as the key significant non-internalized environmental cost for evaluation of energy-efficiency programs. Other air pollutants from generators (NO_x, SO_2, particulates, mercury) have been and are being significantly reduced through direct regulation, and NO_x and SO_2 are subject to cap-and-trade regulations that charge generators for their remaining emissions. Other environmental effects, such as water discharges, are not clearly related to energy usage. AESC 2011 calculates these externalities based upon a "sustainability-target" approach as described in Chapter Six.

2.6. Wholesale Risk Premium

The retail price of electricity supply from a full-requirements fixed-price contract over a given period of time is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary-service in effect during that supply period.

This premium over wholesale prices, or *wholesale risk premium,* is attributable to various costs that retail electricity suppliers incur in addition to the cost of acquiring wholesale energy, capacity, and ancillary-service at wholesale market prices. These additional costs include costs incurred to mitigate cost risks associated with uncertainty in charges that will be borne by the supplier but whose unit prices cannot be definitely determined or hedged in advance. These cost risks include costs of hourly energy balancing, transitional capacity, ancillary services, and uplift.

The larger component of the risk is the difference between projected and actual energy requirements under the contract, driven by unpredictable variations in weather, economic activity, and/or customer migration. For example, during hot summers and cold winters load-serving entities (LSEs) may need to procure additional energy at shortage prices while in mild weather they may have excess supply under contract that they need to “dump” into the wholesale market at a loss. The same pattern holds in economic boom and bust cycles. In addition, the suppliers of power for utility standard-service offers run risks related to migration of customer load from utility service to competitive supply (presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss) and from competitive supply to the utility service (at times of high market prices, forcing the supplier to purchase additional power in a high-cost market).

AESC 2011 applies the same wholesale risk premium to avoided wholesale energy prices and to avoided wholesale capacity prices.[46]Estimates of the appropriate premium range from less than 8 percent to around 10 percent, based on analyses of confidential supplier bids, primarily in Massachusetts, Connecticut, and Maryland, to which the project team or sponsors have been privy. Short-term procurements (for six months or a year into the future) may have smaller risk adders than longer-term procurements (upwards to about three years, which appears to be the limit of suppliers’ willingness to offer fixed prices). Utilities that require suppliers to maintain higher credit levels will tend to see the resulting costs incorporated into the adders in supplier bids.

In the absence of robust information on the retail premium implicit in the prices being bid for retail supply in New England we assume 9 premium as a default risk premium. The risk premium will be a separate input to the avoided-cost

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[46]Capacity costs present a different risk profile than energy costs. With the advent of the Forward Capacity Market, suppliers have a good estimate of the capacity price three years in advance and of the capacity requirement for any given set of customers about one year in advance. (Reconfiguration auctions may affect on the capacity charges, but the change in average costs is likely to be small.) On the other hand, since suppliers generally charge a dollars-per-MWh rate, and energy sales are subject to variation, the supplier retains some risk of under-recovery of capacity costs. There is no way to determine the extent to which an observed risk premium in bundled prices reflects adders on energy, capacity, ancillary services, RPSs, and other factors. Given the uncertainty and variability in the overall risk premium, we do not believe that differentiating between energy and capacity premiums is warranted under this scope of work. We thus apply the retail premium uniformly to both energy and capacity values.

spreadsheet. Therefore, program administrators will be able to input whatever level of risk premium they feel best reflects their specific experience, circumstances, economic and financial conditions, or regulatory direction.

The details of the risks and costs of serving load are somewhat different for Vermont, Public Service of New Hampshire (PSNH), and various municipal utilities, where vertically-integrated utilities procure power from owned resources and a variety of long- and short-term contracts. For Vermont, we will include the 11.1 premium risk premium mandated by the Vermont Public Service Board. For PSNH and the municipal utilities, program administrators should use a risk premium less than the 9 premium default.

2.7. Reserve Margin Requirements

The New England ISO acquires sufficient capacity to ensure reliability in each power-year. In the FCM, the absolute cost of that capacity equals the required capacity, i.e. the installed capacity requirements (ICR), times the FCA auction price. The percentage by which the ICR exceeds the projected system peak is the reserve margin.

The assumptions regarding ISO-NE specified reserve margins for AESC 2011 are presented in Chapter 6.

2.8. Adjustment of Capacity Costs for Losses on ISO-Administered Pool Transmission Facilities

There is a loss of electricity between the generating unit and the ISO's delivery points, where power is delivered from the ISO-administered pool transmission facilities (PTF) to the distribution utility local transmission and distribution systems. Therefore, a one kilowatt load reduction at the ISO's delivery points, as a result of DSM on a given distribution network, reduces the quantity of electricity that a generator has to produce by one kilowatt plus the additional quantity it would have had to generate to compensate for losses.[47] The energy prices forecast by the Market Analytics model reflect these losses. However, the forecast of capacity costs from the FCM do not. Therefore, the forecast capacity costs should be adjusted for these losses.

[47] Computations of avoided costs sometimes assume that only average, and not marginal, losses are relevant at the peak hour. The reasoning for that approach is that changes in peak load will lead to changes in transmission and distribution investment, keeping average percentage losses approximately equal. The AESC 2007 avoided costs do not include any avoided PTF investments, so marginal losses are relevant in this situation.

The ISO does not appear to publish estimates of the losses on the ISO-administered transmission system at system peak. We estimated the marginal peak losses on the PFT system for each summer 2006–2008 by regressing the system losses against real-time demand for the top 100 summer hours. We computed losses as the difference between ISO-reported values for System Load, which it defines as the sum of generation and net interchange, minus pumping load, and Non-PTF Demand, the term that the ISO uses for the load delivered into the networks of distribution utilities. While PTF losses probably vary among zones, marginal losses by zone could not be identified using the available data.

While there was a large scatter in the data (probably due to plant availability, import availability, and the changing geographical mix of load), there was a clear upward trend in losses with load as shown in Exhibit 2-13 and Exhibit 2-14 below.

Exhibit 2-13: PTF Losses vs. Non-PTF Demand for the Top 100 Summer Hours, 2006

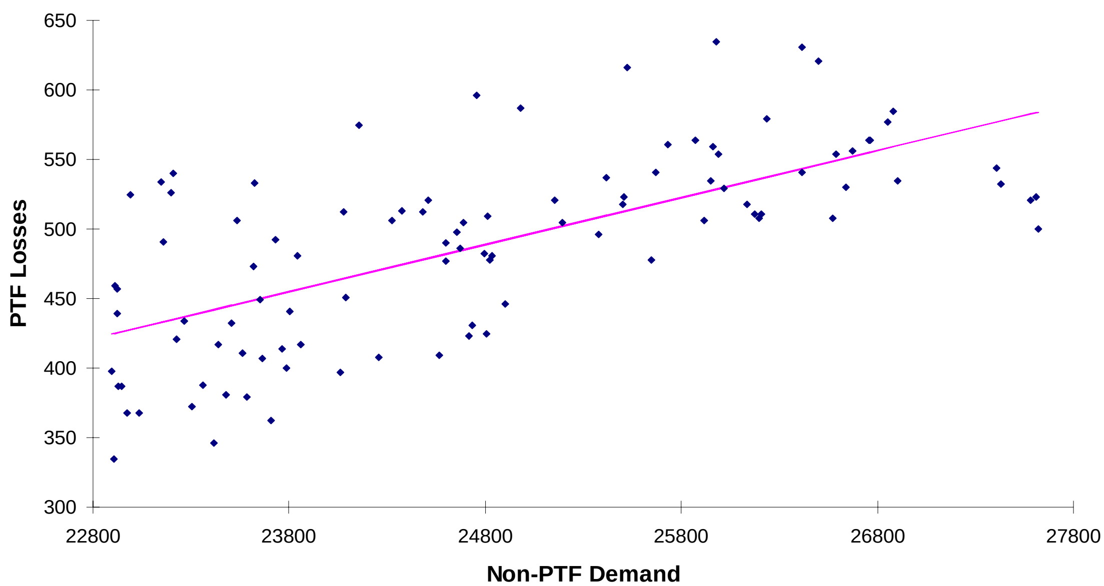
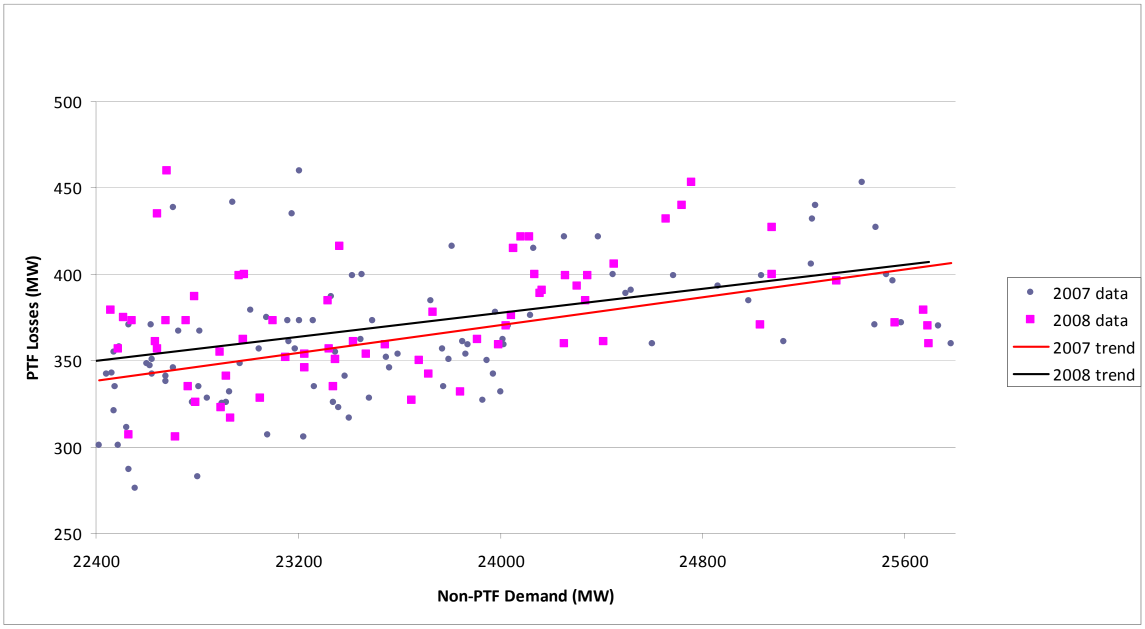


Exhibit 2-14: PTF Losses vs. Non-PTF Demand for the Top 100 Summer Hours, 2007 and 2008



The regression equations (with all variables in MW) were

2006: PTF Losses = 0.0338 × Non-PTF Demand–350.

2007: PTF Losses = 0.0201 × Non-PTF Demand–112

2008: PTF Losses = 0.0177 × Non-PTF Demand–57

The marginal demand loss coefficients were all highly significant, with t-statistics over 5.9.

It is not clear whether the downward shift over time of the data represent permanent changes in the transmission system, load and/or generation dispatch or temporary fluctuations in regional loads and/or dispatch due to weather patterns and the varying ratios of fuel prices.

AESC 2011 estimates the costs of avoiding capacity purchased from each FCA to be the FCA price adjusted by the estimated marginal demand loss factor of 1.9 percent. That factor is an average of the results for 2007 and 2008, which is the same as AESC 2009.

Chapter 3: Wholesale Natural Gas Prices

This Chapter describes the derivation of our projection of wholesale natural gas prices, in constant 2011$, for the New England region and each state over the forecast horizon of 2011 through 2030. It also provides a forecast of natural gas prices for electric generation. The forecast of New England wholesale natural gas prices is an input to the forecast of sector specific natural gas prices presented in Chapters 4 and 6.

The AESC 2011 Base Case price forecast is lower than the AESC 2009 Base Case forecast due to the significant changes in expectations regarding the cost of finding, developing and producing gas from shale gas resources and the quantity of shale gas production.[48] The AESC 2009 forecast was based on our estimate that the full-cycle cost of producing shale gas equated to a Henry Hub price ranging between $6.50 per MMBtu and $8.00 per MMBtu. Our updated estimate of the full-cycle cost of shale gas underlying the AESC 2011 Base Case forecast equates to a Henry Hub price of $5.50 per MMBtu. This updated estimate is based on a more detailed analysis of published data from seven major producers.

The AESC 2011 Base Case forecast is based upon New York Mercantile Exchange ("NYMEX") gas futures prices for the years 2011 to 2014 and the AEO 2010 "High Shale Gas" case forecast for 2015 onward. The AESC 2011 Base Case forecast draws upon NYMEX futures as a reasonable estimate based on short-term market dynamics and the AEO 2010 High Shale case as a reasonable estimate based on long-term market fundamentals. The AEO 2010 High Shale case assumes shale gas unproved resources comparable in size to the AEO 2011 Reference Case and projects prices consistent with our estimate of the full-cycle, all-in cost of finding, developing and producing gas from shale resources.

The AESC 2011 High Price case and Low Price gas case forecasts reflect the considerable uncertainty regarding projections of shale gas production quantities and costs. As AEO 2011 notes, these projections are based upon limited experience with many shale gas formations. As a result the AEO 2011 Reference Case projections may overestimate the quantity of shale gas production or underestimate the future cost of shale gas production. Alternatively, technical advances may reduce production costs and currently untested shale gas formations could prove to be highly productive. In addition, concerns have been raised regarding the need for additional regulation of hydraulic fracturing in order to

[48] This Chapter refers to our forecast as the AESC Base Case rather than Reference Case to minimize confusion with the various AEO Reference cases to which we refer.

minimize its environmental impacts on groundwater, surface water, and air emissions. These concerns create uncertainty regarding the potential impact of future changes in regulation on shale gas production quantities and costs.

3.1. Overview of New England Gas Market

In order to place our forecast of wholesale natural gas prices for New England in context we begin with an overview of 1) natural gas demand in New England, 2) the physical supply of gas to the region, and 3) the "product" that is being purchased at wholesale commodity prices.

3.1.1. Demand for Wholesale Gas in New England

Natural gas accounts for approximately 24 percent of total New England energy consumption.[49] The market for wholesale gas in New England can be grouped into two distinct categories. First, natural gas purchased for direct use by, or on behalf of, very large end-users in the electric-generation, industrial, commercial, and institutional sectors. Second is gas purchased by local distribution companies (LDCs) for re-sale to retail customers in the residential, commercial, and industrial (RC&I) sector.

The annual quantity of natural gas purchased for direct use by very large end users, primarily for electric generation, has increased dramatically since the 1990s. That demand today accounts for roughly half of the annual gas consumption in New England. In its 2011 Annual Energy Outlook (AEO 2011) Reference Case, the Energy Information Administration (EIA) forecast annual gas use for electric generation in New England to grow by an average of 0.6% between 2011 and 2025, and by an average of 1.3% thereafter.[50]

The annual quantity of gas purchased by LDCs for resale to residential, commercial and industrial customers has remained relatively stable since the 1990s. In the Reference Case, annual gas use in this category is forecast to grow at about 0.9% per year between 2011 and 2025.

Actual and projected levels of annual natural gas use in these two categories are presented in Exhibit 3-1 below. (The projections are drawn from the AEO 2011 Reference Case.)

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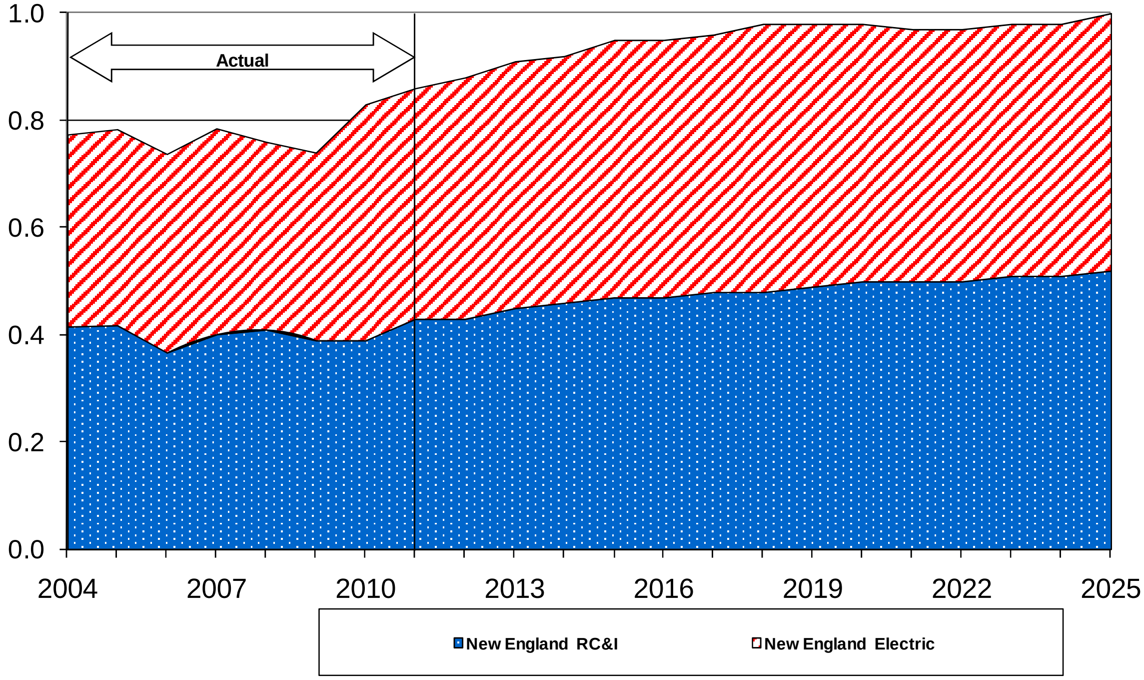
[49] 2008 energy consumption estimates by source in EIA State Energy Data System available at http://www.eia.doe.gov/emeu/states/hf.jsp?incfile=sep_sum/plain_html/sum_btu_eu.html.

[50] AEO 2011, Table 136

Exhibit 3-1: Annual Gas Use (Tcf) in New England Actual and AEO 2011 Reference Case projection

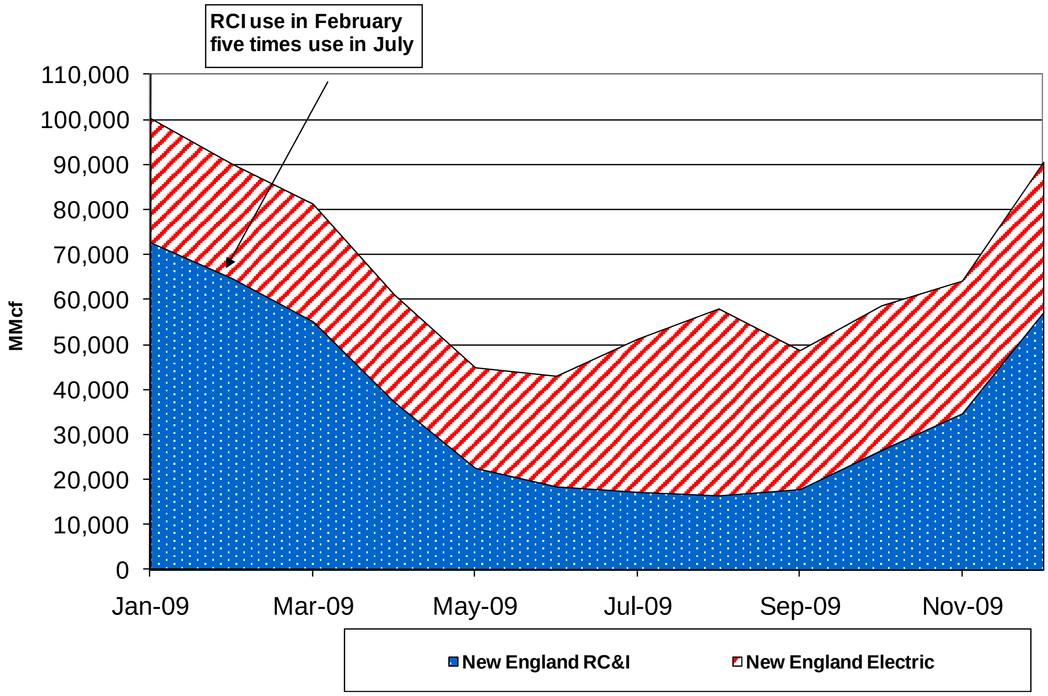


The demand for wholesale gas in New England in these two categories also varies substantially by season, and from month by month within each season.

The quantity of gas for direct use varies by month, with the greatest use occurring in summer months. In contrast, the greatest gas use by retail customers occurs in winter months since the dominant end-use is heating. As a result, LDCs have a much greater seasonal *swing* in gas load during the course of a year. For example, an LDC's gas load in January or February can be five times its load in July or August. Because of these large swings in gas load, LDCs acquire a portion of their winter requirements during the summer, store it in underground facilities outside of New England, and withdraw it during the winter when needed. In addition, LDCs use liquefied natural gas (LNG) and propane stored in New England to meet a portion of their peak requirements on the coldest days of the winter.

The variation in gas use by month in New England in 2009 is illustrated in Exhibit 3-2.

Exhibit 3-2: Monthly Gas Use in New England in 2009



3.1.2. Supply of Wholesale Gas in New England

The natural gas used in New England is acquired from producing regions elsewhere and delivered to the region via pipeline or by ship as LNG. Adequate delivery capacity from producing areas to New England is essential to the firm supply of natural gas to the region.

Most of the gas consumed in New England is delivered by pipeline from producing areas in Appalachia and the Southwest as well as from western Canada, Nova Scotia, and New Brunswick. LNG is delivered by ship from LNG-exporting countries, principally Trinidad and Tobago.

The physical system through which gas is delivered to New England, and within the region, excluding Vermont, currently comprises six interstate and intrastate pipelines and three LNG facilities.

Pipelines deliver gas directly to a number of electric generating units and very large customers, as well as indirectly through deliveries to LDCs who in turn distribute that gas to retail customers. Two pipelines, Tennessee Gas Pipeline and Algonquin Gas Pipeline, deliver the majority of gas to New England. The Tennessee Gas Pipeline delivers primarily into Massachusetts, New Hampshire and Maine while the Algonquin Gas Pipeline delivers primarily into Connecticut and Rhode Island. (Consistent with prior AESC reports this report refers a)

Massachusetts, New Hampshire and Maine as Northern and Central New England and b) Connecticut and Rhode Island as Southern New England.) Also, the Maritimes & Northeast and Portland Natural Gas pipelines deliver into Maine, Massachusetts, and New Hampshire. Those pipelines ultimately deliver into the Tennessee Gas system at the interconnection in Dracut, Massachusetts and into Algonquin via the Hubline project from Beverly to Weymouth, Massachusetts. The Iroquois Gas Pipeline delivers into Connecticut while Granite State Pipeline delivers gas in New Hampshire and Maine. The one LDC serving northern Vermont receives its gas from TransCanada Pipelines at Highgate Springs on the border with Canada.

LNG is delivered to three LNG facilities in New England and one in New Brunswick. The three LNG facilities in New England are Distrigas in Everett, Massachusetts, the Northeast Gateway facility offshore Cape Ann, Massachusetts and the Neptune LNG facility completed in 2010 off the coast of Gloucester. The Distrigas facility delivers gas into the Algonquin Gas Pipeline, the National Grid (formerly KeySpan) system, the Mystic Electric Generating Station, and sends LNG by truck to LDC storage tanks throughout the region. The Northeast Gateway and Neptune facilities deliver gas into the Algonquin Gas Pipeline via the Hubline. The Canaport LNG facility in Saint John, New Brunswick began operating in June 2009 and delivers gas into the Brunswick Pipeline which connects to the Maritimes and Northeast Pipeline.

A more extensive discussion of the New England gas industry and gas supply is published by the Northeast Gas Association (2010).

3.1.3. Prices for Purchases of Wholesale Commodity Supply in New England

The AESC 2011 forecast of commodity prices for wholesale supply in each New England state, and in the region in general, are for a monthly supply of gas expressed in dollars per million Btu ($/MMBtu). These are prices for one of the major "products" that is bought and sold in the wholesale market in New England. For example, one product is a one month supply of gas for delivery at one of the region's market hubs.[51] Another major product is a one day supply of gas for delivery at a market hub. The prices for these monthly and daily products are published in various gas industry publications.

The first and largest component of the forecast price for this product is a forecast of the monthly commodity price at the Henry Hub (HH), which is located in

[51] The major market hubs in New England are Tennessee Gas Pipeline Zone 6, Algonquin Gas Pipeline City Gate, and Dracut.

Louisiana and is the most liquid trading hub in North America, as described in more detail below. The second component is an estimate of the *basis differential* between the wholesale price of natural gas at the Henry Hub and the wholesale price of natural gas at the relevant market hub in New England.

Thus, the forecast of wholesale natural-gas prices in New England in each month are estimates of the market value of a spot supply of gas at that location in that month. As such the wholesale commodity price in a given month does not necessarily reflect the actual long-term fixed costs that a seller would incur to ensure firm delivery of natural gas to New England every month of the year over a long-term planning horizon. This forecast will be a key input to the forecast of regional electric-energy-supply prices. Natural gas-fired plants base their daily bids into the wholesale electric energy market on the corresponding market value or opportunity cost of a one day supply of natural gas in New England for that day. Our forecast of wholesale gas prices by month is a reasonable proxy for those daily prices over time.

The forecast of monthly wholesale prices in New England is not be an input to the forecast of retail natural-gas prices for residential, commercial and industrial customers, which, as described in chapter 4, LDCs who serve customers in those categories purchase gas from major producing areas at prices tied to the Henry Hub price and assure firm delivery of that gas to their city-gate receipt points through long-term contracts for firm pipeline transportation service and underground storage service. [52] Some LDCs also acquire supply from local LNG facilities.

3.2. Gas Forecast Methodology

3.2.1. Henry Hub as a Starting Point

The forecast of wholesale commodity prices of gas in New England begins with a forecast of the price of gas at the Henry Hub. These prices are the most relevant starting point for forecasting US gas supply costs for several reasons.

First, the Henry Hub is located in the U.S. Gulf Coast area, which is the dominant producing region of the United States. As indicated in Exhibit 3-3, AEO 2011[53] projects production from the “Lower 48” will be the dominant source of physical gas supply to U.S. markets over the AESC 2011 study period. In 2010 that production accounted for about 87% of US supply with the remaining supply coming from imports via pipeline, primarily from Canada, and by ship as LNG.

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[52]A city-gate is a point at which a pipeline delivers gas into the system of an LDC.

[53] EIA Annual Energy Outlook 2011 published April 26, 2011. www.eia.gov/forecasts/aeo

AEO 2011 projects U.S. production to increase to approximately 93% of total national supply by 2020 due primarily to forecast increased production from shale gas. AEO 2011 projects a corresponding decline in pipeline imports from Canada, and little charge of LNG.

Exhibit 3-3: Sources of US Natural-gas Supply 2010 and 2020 (Trillion cubic feet)

Sources of Supply	**2010** (Actual)	**2020** (AEO 2011: Reference Case)
Shale gas production	**4.80**	**8.21**
Other categories of gas production	16.55	15.28
US Production, incl. Alaska & Supplemental	21.35	23.49
Imports via Pipeline	2.33	1.40
Imports via LNG	0.44	0.50
Total	24.12	25.39

Source: AEO 2011 (Tables 13 & 14).

Second, the market for wholesale natural gas is a North American market. The Henry Hub is the most liquid trading hub with the longest history of public trading of NYMEX gas futures contracts. The wholesale market prices of gas in various regions of the United States and Canada reflect Henry Hub prices with an adjustment for their location—generally referred to as a basis differential. A basis differential is the difference between the wholesale natural-gas price at a given market hub and the corresponding Henry Hub natural gas price.

3.2.2. Forecast Methodology

Consistent with the approach used to develop the gas price forecast in AESC 2007 and AESC 2009, the AESC 2011 Henry Hub gas price forecast is based upon data from two sources - futures prices from the New York Mercantile Exchange (NYMEX) for the near-term and a forecast from an appropriate Annual Energy Outlook forecast for the long-term. Using this methodology we developed a Base Case forecast of Henry Hub gas prices that is a “blend” of NYMEX and AEO projections. Specifically, it is NYMEX futures (as of March 18, 2011) through

2014 and prices projected in the AEO 2010 "High Shale Gas Resource" case of AEO 2010 from 2015 onward.[54]

This methodology is used by many forecasters, including various electric utility IRPs, and is consistent with reports by the National Regulatory Research Institute and Lawrence Berkeley Lab. It reflects the fact that futures prices are generally considered to provide the most accurate forecast of near-term Henry Hub natural gas prices while forecasts from a model that simulates market fundamentals of physical demand, physical supply and long-run marginal costs of supply provide a better estimate of long-term prices.

3.2.2.1. NYMEX Prices

We rely on futures prices in the near term because they reflect the purchases of many buyers and the sales of many sellers. We limit our reliance upon futures prices to the near-term because NYMEX prices for outer years are not established through the transactions of many buyers and sellers.[55]

NYMEX futures have been quite consistent since August 2010 as shown in Exhibit 3-4.

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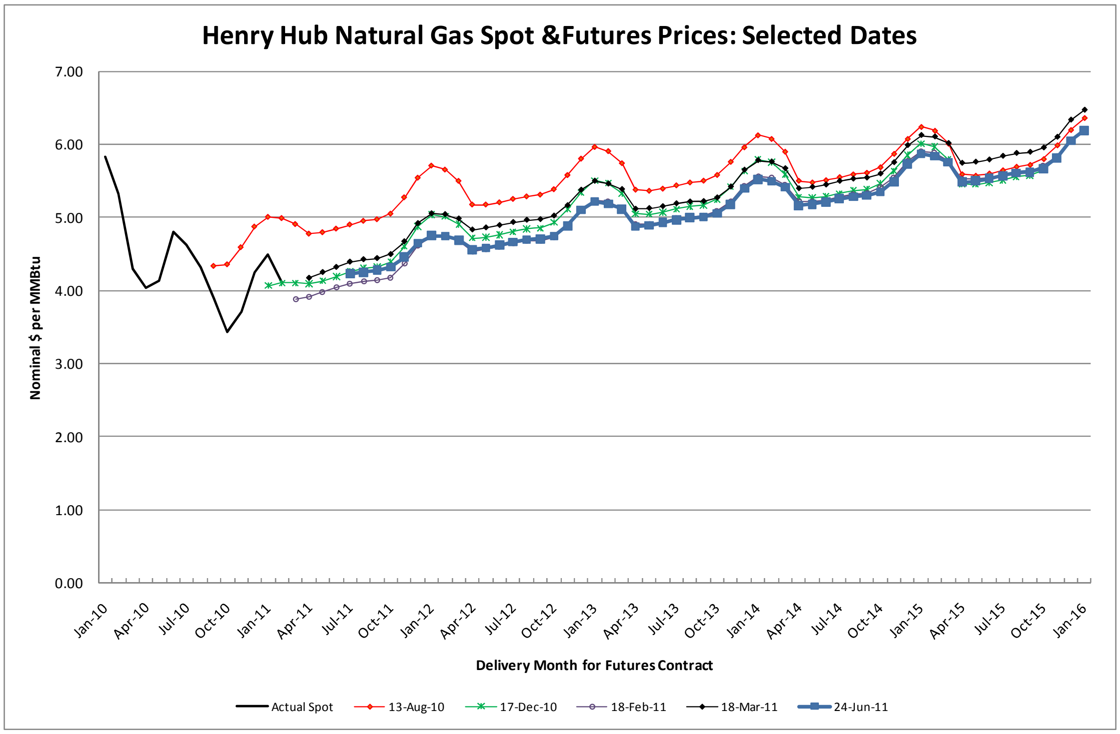
54 In order to develop consistent inputs for the AESC 2011 model and all analyses, the Project Team needed a single pricing date. The project team checked NYMEX futures as of June 24 to verify that the futures as of March 18 remained valid.

55 A market is considered to be "liquid" if changes in demand for the product being bought and sold, or changes in the supply of that product, causes small changes in the price of the product. Markets with a high level of liquidity provide accurate prices because they have the characteristics of the textbook economics "perfect" market, i.e., multiple well-informed buyers, multiple well-informed sellers, ease of market exit and ease of market entry. Analyses routinely demonstrate that the liquidity of the Henry Hub Natural Gas Futures is very high for near term months, e.g. out 12 to 24 months, but is very low for months further out in the future.

Exhibit 3-4: Recent Futures Prices



3.2.2.2. AEO Forecasts

For the long-term we rely upon forecasts from an appropriate AEO case because the inputs and model algorithms underlying the AEO projections are public, transparent and incorporate the long-term feedback mechanisms of energy prices upon supply, demand, and competition among fuels. Our selection of which specific AEO forecast to rely upon was informed by our analysis of the full cycle cost of finding, developing and producing shale gas. We focused upon shale gas because, consistent with most analysts, we expect shale gas to be the dominant marginal source of supply, and market price setter, in the long-term.

3.3. Estimated Costs of Finding and Producing Natural Gas from Shale in North America

Shale gas refers to natural gas produced from shale formations. To extract gas from those formations, companies drill wells vertically down for 3,000 to 15,000 feet to the shale layer and then horizontally for 2,000 to 5,000 feet through the shale layer. The well is often cased with pipe cemented in place and the shale rock near the horizontal well bore is fractured. To fracture the shale rock, water is injected under high pressure which opens cracks in the shale and sand mixed with the water moves into the cracks to hold them open when the pressure is removed.

Natural gas from the shale layer then flows through these cracks into and up the well.

In 2009 we identified shale gas as an important and growing source of gas supply in the U.S. which had become the marginal source of natural gas and thus would set the price of natural gas at the Henry Hub. Since 2009 exploration for and production of gas from U.S. and more recently Canadian shale has grown faster than expected in 2009. The result has been a rapid expansion of gas production, which combined with the recession of 2008, has resulted in ample supply and dramatic decreases in the annual average price of natural gas. For example, the annual average Henry Hub price dropped from $8.86 per MMBtu in 2008 to $3.94 in 2009 and then rose slightly to $4.37 in 2010.[56]

The dramatic change in expectations for shale gas production is reflected in the AEO 2011 Reference Case projection of 8.21 Tcf from shale in 2020 compared with a projection of 2.7 Tcf from shale in 2020 according to the AEO 2009 Update.[57] Thus, shale gas has assumed an even more important role in setting the price of natural gas in the U.S. There has been very rapid leasing of shale gas producing areas and a rapid rise in drilling these leases with horizontal drilling since early to mid-2009. This rise in drilling occurred even as gas prices averaged $3.94 per MMBtu in 2009 and seldom rose above $5.00 per MMBtu at the Henry Hub.

AESC 2011 projects that, as the marginal source of natural gas, the costs of finding, developing and producing shale gas should set the long-run price of natural gas. This projection is based upon our assumption that, in the long run, companies will not spend money to find and produce shale gas unless they expect the revenues from the sale of that gas to cover their costs plus provide an acceptable rate of return on invested capital. Thus we compute the full-cycle cost of shale gas, including a rate of return.

Because independent producers have concentrated so much on exploiting shale gas, we can examine their SEC Form 10-K data to estimate their full-cycle costs of shale gas.[58] In order to develop an estimate of the "full-cycle" costs of exploiting

[56]Henry Hub spot price from EIA website in nominal dollars. Supplied by Thompson Reuters.

[57] AEO 2009 Update and AEO 2011 early release Table 17: Oil and Gas Supply.

[58] The large international, integrated producers such as Exxon-Mobil, Chevron, and BP have until recently been absent from developing the shale gas resource. However in 2008, BP purchased all of the Woodford Shale interests and then 25% of the Fayetteville shale interests of Chesapeake Energy. In 2010, Exxon-Mobil purchased all of XTO Energy. Chevron purchased Atlas Energy with large holdings in the

U.S. shale gas we obtained and analyzed data reported for 2010 in 10-K filings and other sources by seven major companies active in shale gas development - Cabot Oil and Gas (COG), Chesapeake Energy (CHK), Comstock Resources (CRK), Devon Energy (DVN), EOG Resources (EOG), Range Resources (RRC) and Southwestern Energy (SWN). Highlights from our analysis of that data are reported in exhibit 3-5.

Three of the companies, Chesapeake, Devon and EOG; are very large producers (Chesapeake is the second largest gas producer in the U.S. behind Exxon). Two concentrate in specific and apparently low-cost shale areas: Cabot in the Marcellus shale and Southwestern in the Fayetteville shale. Comstock and Range Resources are small but representative producers. A list which ranks shale producers by their costs show these seven to be among the 17 lowest finding-and-operating cost producers among the 54 listed.[59]

Marcellus shale in early 2011. BHP Billiton agreed to buy all of Chesapeake Energy's remaining interests in the Fayetteville shale during 2011.

[59] Comstock Resources, March 2011 Presentation, page 26. Operating costs based on data from the first 3 quarters of 2010 and finding costs based on 2009 data.

Exhibit 3-5: Natural Gas Wellhead Prices Implied by Estimated Full-Cycle Costs of Selected Oil & Gas Companies (2010 Data)

Company Stock Symbol	Units	Cabot O & G COG	Chesapeake CHK	Comstock CRK	Devon DVN	EOG Resources EOG	Range RRC	Southwestern SWN	Average Price excl SWN
I. Company Characterization									
Production in 2010									
Natural Gas	Bcf	125.5	924.9	70.0	930.0	633.4	142.0	403.6	
Crude Oil and NGLs	million bbls	0.8	18.4	0.7	73.0	38.4	6.5	0.2	
Total Revenues	million $	$844.0	$9,366.0	$349.1	$9,940.0	$6,099.9	$1,039.0	$2,610.7	
Net Profit in 2010	million $	$103.4	$1,774.0	($19.6)	$2,333.0	$160.7	($239.3)	$603.8	
II. Reserve and Cost Data					(c)				
Additions to O&G Proved Reserves (a)	Bcfe (b)	650.6	5,098.0	430.6	2,124.0	2,375.9	1,410.4	1,431.1	
Proved Developed (PD)	Bcfe	258.8	1,888.0	174.4	1,254.0	846	261.1	697.9	
Proved Undeveloped (PUD)	Bcfe	391.8	3,210.0	256.2	870.0	1,530.0	1,149.3	733.2	
Estimated Finding and Developing (F & D) Costs									
a **For Proved Developed (PD) Reserves**	$/Mcfe	1.74	2.43	2.44	2.35	2.25	2.60	1.60	
b **To Convert PUDs to PD**	$/Mcfe	0.85	1.35	1.34	1.70	1.81	1.00	1.47	
c **Weighted Average of a & b**	$/Mcfe	$1.29	$1.89	$1.89	$2.03	$2.03	$1.80	$1.54	
Estimated Cash Expenses									
Production	$/Mcfe	0.70	1.00	1.10	1.28	0.83	0.75	0.90	
Production Taxes	$/Mcfe	0.35	0.27	0.20	0.29	0.37	0.17	0.11	
G & A	$/Mcfe	0.60	0.37	0.35	0.43	0.33	0.60	0.34	
Interest	$/Mcfe	0.50	0.80	0.40	0.20	0.15	0.70	0.14	
Sub-total	$/Mcfe	$2.15	$2.44	$2.05	$2.20	$1.68	$2.22	$1.49	
III. Estimate of Required Natural Gas prices									
Required Wellhead Price @ 20% IRR	**$/Mcfe**	**$5.31**	**$5.16**	**$4.63**	**$5.12**	**$4.61**	**$4.82**	**$3.70**	$4.94
Basis to Henry Hub (d)	$/Mcf	na	$ 1.00	na	10%	na	$ 0.68	$ 0.47	$ 0.76
Estimated Henry Hub price									
	$/Mcf		$6.16		$5.69		$5.50	$4.17	$5.70
At 1.03 MMBtu/Mcf	$/MMBtu		$5.98		$5.52		$5.34	$4.05	$5.54

Data Source: Analyses of SEC Form 10Ks for 2010 and various company presentations and publications.
(a) Excludes revisions to reserves. 1 barrel of oil equals 6 Mcf of gas.
(b) Bcfe is Billion of cubic feet equivalent in which 1 barrel (bbl) of oil = 6 Mcf.
(c) Net earnings from continuing operations; excludes earnings from discontinued operations.
(d) In AEO 2010 the difference between the wellhed price and the Henry Hub spot price is approximtely $0.74 per MMBtu or $0.76 per Mcf.

3.3.1.1. Reserve and Cost Data

We begin our analysis of the full-cycle cost of shale gas by examining two sets of costs (1) finding and developing (F & D) costs and (2) production costs. The first set is the cost of finding and developing a unit of proved reserves, which is expressed as $ per Mcf[60] of proved reserves that is underground. The second set is the production cost, which represents the cost of bringing the gas from the underground reservoir to the wellhead at the surface. Beyond the wellhead there are additional costs to gather the gas from various wellheads, process the gas to bring it to pipeline quality and transport the gas to a high-pressure transmission pipeline. Our estimates of these two sets of costs for seven companies are presented in section II of Exhibit 3-6.

Estimates of Finding and Developing ("F&D") Costs

Companies incur finding and development costs for the following activities: 1) geological and geophysical surveys, 2) purchase of leases giving the right to the producer to look for and produce oil and gas under specific landholdings, and 3) drilling and completion of wells.

In addition to the direct costs for those three activities, companies incur indirect costs such as general and administrative (G & A) costs associated with F & D activities and interest costs, such as those to finance the purchase of leases, which also are directly attributable to the F & D stage. Analysts divide those direct and indirect costs by the proved reserves found in the F&D stage to obtain the unit F&D cost per Mcf of finding and developing proved reserves.

Our estimates of unit F&D costs, shown in Exhibit 3-5, distinguish between the unit F&D cost of adding new "proved developed" reserves (PD) and the unit F&D costs of converting "proved undeveloped" reserves (PUD) into PD reserves. We make this distinction because of the difference between PD and PUD reserves. Proved developed reserves refer to gas in the underground reservoir that can be produced by existing wells and associated surface equipment. Proved undeveloped reserves refer to gas which the relevant company believes to be in the underground reservoir that can be produced when new wells are drilled and completed and new surface equipment is installed. Not surprisingly, the costs of finding new PD reserves are higher than converting PUDs to PD reserves. Finding new reserves includes geological and geophysical costs, the cost of lease acquisition and the costs of exploration that fails.

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60 An Mcf is one thousand cubic feet of gas at standard conditions, which contains about 1.03 million Btu of heat content.

Our estimates of total unit F & D costs are shown in the Reserve and Cost Data section of Exhibit 3-5 at line c. These totals reflect the fact that companies incur a blend of F & D costs to add PD reserves and to convert PUD reserves to PD. Our total uses a 50-50 weighting based on judgment and the approximate quantities of each category of reserves reported for 2010.

Our estimates of total unit F&D costs tend to be higher than the total F&D costs generally reported in company presentations because those presentations generally do not make this distinction between PD and PUD reserves. Instead, the presentations typically report total unit F & D costs equal to total absolute F&D costs in a year divided by the total of proved reserves, PD and PUDs found in that year. As can be seen in the Reserve and Cost Data section of Exhibit 3-5, with the exception of Devon, each of the companies reported a higher quantity of PUD reserves in 2010 than PD reserves. We believe that estimates of total unit F & D costs that do not distinguish between unit F&D costs of PD reserves and unit F&D costs of PUD reserves understate actual F&D costs. The Companies will need to drill and complete new wells, and install new surface equipment, before PUDs reserves can produce gas.

Drawing distinctions between proved developed and proved undeveloped reserves is especially important when using 10-K data from the 2010 reports. The SEC altered and relaxed its definitions of proved developed and, more importantly, of proved undeveloped reserves, effective January 1, 2010.[61] One important change is to allow PUDs to include reserves more than one offset well away from a producing well. Another change very useful to estimating F & D costs in 2010 is the SEC requirement that producers disclose changes in PUDs from year to year, including both the amount of reserves changed from PUD to PD and the cost of the associated wells. The net result of the rule changes is not clear but it may have increased PUDs.[62]

Estimates of Production Costs

The costs to produce gas are the cash expenses that are incurred. They include what we label production costs, which are also called lease operating expenses (LOE). This category includes costs for the maintenance and operation of lease equipment, recording of measurements, labor costs, workovers, property taxes, insurance, etc. In addition, there are production taxes, also called severance taxes,

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61 Ryder Scott Petroleum Engineers, Reservoir Solutions, A Quarterly Newsletter, Vol. 12, No. 1 (March – May 2009)

62 Ryder Scott, Vol. 13, No. 1 (March-May 2010)

the G & A expenses of the company, and interest costs. The total is the cash expenses of production.

One issue that must be discussed is royalty. When a landowner sells a lease to a producer he keeps a royalty interest (RI) in the production from the property, which is generally 15 – 25 percent in the shale gas areas. The producer has a working interest (WI) in the production which is the remaining interest in the production. The owner of the RI receives cash from the sale of production, which is generally based on the value at the wellhead. The RI bears no cost for finding, development or production, but does generally pay its share of production taxes. The producer pays all the cost of finding, development and production.

The cost of royalty is very high to the producer, but it is not represented in Exhibit 3-5. Oil and gas accounting in the United States, as prescribed by the SEC for its Form 10-K, specifies that both reserve quantities and production quantities be specified on a net interest basis.[63] Thus, the reserves and production for a producing company do not include reserves or production quantities related to the royalty owner's interest or to the working interest of others. Similarly, revenues received by a producer reflect only its interest in the sale of production; the money received by the royalty owner is excluded from the producer's reporting of revenue. The costs of finding, developing and producing are applied only to the producer's working interest volumes. Thus 100% percent of these costs are applied to the 75-85% of reserves and production owned by the producer. The cost of royalty is taken care of by the way the accounting is specified, and is not explicitly represented here in our calculation of the full-cycle costs of gas. Rather, the costs of royalty are implicitly represented by the accounting definitions of reserves, production and the associated costs.

3.3.1.2. Required Well-Head and Henry Hub prices Required to Recover Full-Cycle Costs

Since there is a lag in time between investment in finding and developing shale gas reserves and the revenue that comes from producing and selling the gas from those reserves, the standard approach to estimate the price needed to cover full-cycle costs is to use a present value model representing the cash flow of the business. Cash inflow is the revenue generated by the sale of gas. Cash outflow is the initial investment, the cash expenses of production and annual payment of income taxes. Then a price is found that applied over the period of the model produces a target internal rate of return on the cash flow.

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63 Charlotte J. Wright & Rebecca A. Gallun, Fundamentals of Oil & Gas Accounting, 5th Edition, PennWell (2008), pages 619, 625 and 627.

Our present value model has the following assumptions:

1. Ten year life with all investment and initial gas production in the first year.
2. The present value calculation is from mid-year.
3. A target internal rate of return of 20 percent per year is used.
4. Investment is the finding and development costs shown in Exhibit 3-5. In the first year 70 percent is expensed and 30 percent is depreciated over eight years, including one-half first year, according to an IRS prescribed MACRS 200 percent double declining balance method.
5. Gas production starts at the middle of the first year and declines at an exponential rate of 60 percent per year for the first four years and from years 5 through 10 is 5 percent of the initial production.
6. The cash expenses as shown in Exhibit 3-5 are based on production each year.
7. Income tax is 39 percent to represent both federal and state income taxes.
8. A wellhead price for the gas is found that produces a zero net present value.

The results are shown in the bottom portion of Exhibit 3-5 in the "Required Wellhead Price" line. Not surprisingly, the required wellhead price to cover full-cycle costs varies from company to company. However, with the exception of Southwestern Energy, there is a relatively small ($0.60 per Mcf) difference between the required wellhead prices of the other six producers. Excluding the Southwestern Energy price, the average wellhead price is $4.94 per Mcf

But the wellhead price is not the price of gas at the Henry Hub. After gas leaves the wellhead any heavy liquids, such as condensate, are removed. The remaining gas is then piped in a gathering pipeline system to a processing plant where lighter natural gas liquids (NGLs) such as propane, butane and sometimes ethane are removed. The NGLs have more value per Btu than does the pipeline quality gas, but the cost for gathering the gas and removing the liquids must be paid. After processing the gas is piped to a high pressure pipeline, which incurs costs of the transportation and perhaps costs of compression. According to the AEO 2010 the average difference in price between the wellhead and the Henry Hub is $ 0.74 per MMBtu or $ 0.76 per Mcf at 1.03 MMBtu per Mcf converted to 2011$. Thus, using the full-cycle costs we estimate the price of gas at the Henry Hub is $5.70 per Mcf or $5.54 per MMBtu.

This full-cycle cost based price is significantly higher than the Henry Hub spot price on March 18, 2011 of $3.94 per MMBtu or even than the Henry Hub futures 12 month strip price on March 18, 2011 of $4.59 per MMBtu.

One check on this full-cycle cost estimate is to compare it to what gas industry leaders are saying. Mr. Aubrey McClendon, CEO of Chesapeake Energy, said, "We estimate the marginal cost of gas supply in the US is around $5.50 per Mcf."[64] He did not say whether this was at the wellhead or at the Henry Hub. Mr. Jeff Ventura, COO Range Resources, and Mr. Larry Nichols, CEO Devon Energy, "…agreed that a wellhead price of $5 - 7/Mcf at the oil field service operating costs of about a year ago should be sufficient for a 20% rate of return in most US basins (of unconventional oil and gas plays) due to the size of the unconventional resource, but they did not speculate on when the gas price might rise to that range."[65] Mr. George Kirkland, head of E & P for Chevron Corp. said gas prices "in the $6s and $7s are needed over the long term to cover unconventional resource investment costs." referring to U.S. shale plays.[66]

But for U.S. natural gas prices to rise from the levels of the last two years the supply-demand balance must shift to greater demand and/or less supply. There is some indication that the supply of natural gas from the U.S. may decline. The independent producers, particularly the large ones such as Chesapeake, Devon and EOG Resources, all plan to shift exploration and drilling to U.S. places where production will be liquids rich either for crude oil and condensate or at least larger volume NGL production associated with natural gas production. They plan to reduce drilling for dry gas. This shift appears to be under way. According to the weekly active drilling rig report from Baker-Hughes, rigs drilling for natural gas in the U.S. peaked in August 2010 at 983 rigs and for the four weeks ending March 18, 2011 the average number of rigs drilling for gas had dropped to 891. For the four weeks ending May 13, 2011 the number of rigs drilling for gas was 881.

3.4. Review of AEO 2011 and AEO 2010 Forecasts

The next step in developing a forecast of annual Henry Hub natural-gas prices is to review the forecasts available from AEO 2011 and AEO 2010 to determine which forecast is most consistent with our estimate of the Henry Hub price needed to cover the full-cost of shale gas.

Exhibit 3-6 below shows, in 2011$, the AEO 2009 Update Reference case forecast, the AEO 2010 Reference Case forecast, the AEO 2010 High Shale case forecast and the AEO 2011 Reference Case forecast. It also plots the NYMEX futures price settlements on March 18, 2011. The AEO 2011 ER Reference case forecast seemed particularly low, not reaching the $5.50 Henry Hub price we estimate as need to recover full cycle shale gas costs until 2022.

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64 Chesapeake Energy, 4th quarter earnings conference call, February 23, 2011.

65 Oil and Gas journal, "Industry Climbs unconventional learning curves", October 11, 2010, page 27.

66 NGI Shale Daily, "Chevron's U.S. Shale Plays to 'Generate Opportunities,' says E&P Chief", March 21, 2011; page 2.

Exhibit 3-6: Comparison of EIA Henry Hub Natural Gas Price Forecasts & NYMEX Futures as of March 18, 2011 (2011$ per MMBtu)

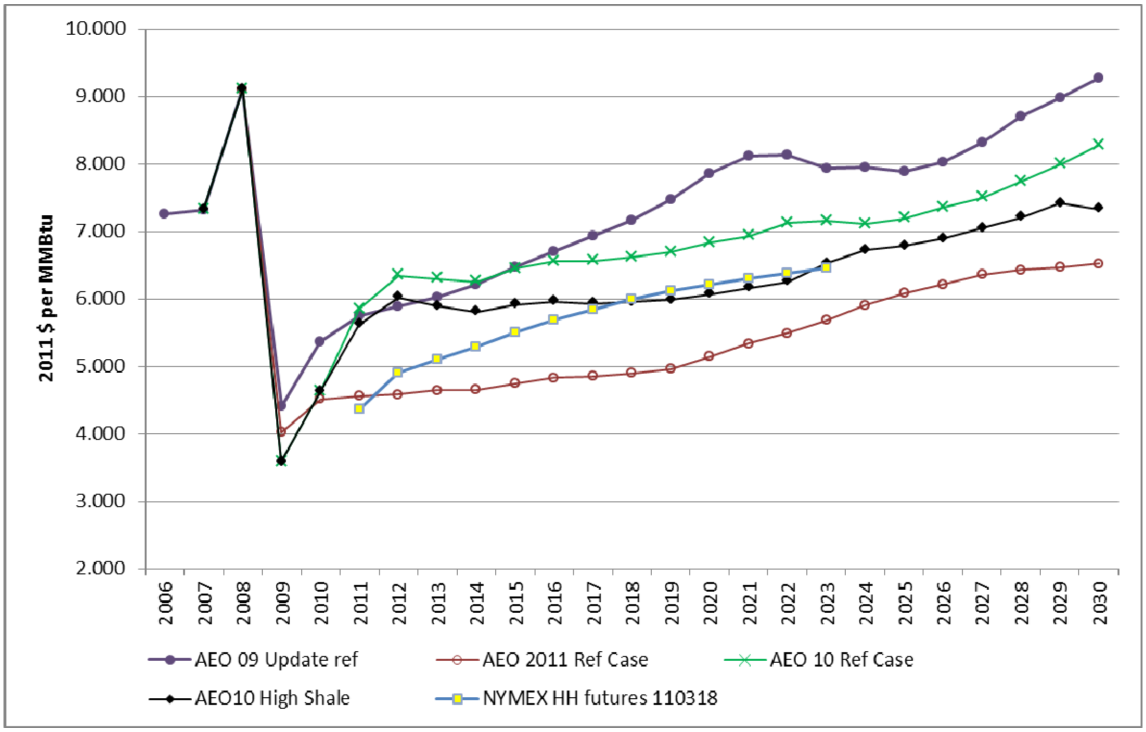


Exhibit 3-7 reviews actual values for 2010 and projections for 2020 for several key parameters including gas production and gas prices. The projections are from the AEO 2009 Reference case (the basis for AESC 2009 Base Case), the AEO 2010 Reference Case, the AEO 2010 High Shale case basis for AESC 2011 Base Case) and the AEO 2011 Release Reference Case. The values for GDP, total electricity production and crude prices are very similar. The major differences are in the Henry Hub price and shale gas production. These differences reflect the very different assumptions about the size of the shale gas resource (Unproved Shale Gas Resource) among the various cases as of the time those case forecasts were prepared:

- 267 Tcf in the AEO 2009 Reference Case;
- 347 Tcf in the AEO 2010 Reference Case and Slow Oil & Gas Technology Case;
- 652 Tcf in the AEO 2010 High Shale Case; and
- 827 Tcf in the AEO 2011 Reference Case.

Exhibit 3-7: Comparison of results of AEO 2011 Reference Case, AEO 2010 High Shale, AEO 2010 Reference Case, and AEO 2009 Reference Case

			Forecast for Year 2020			
	units	Actual 2010	AEO 2011 Reference	AEO 2010 High Shale	AEO 2010 Reference	AEO 2009 Reference (g)
Supply of Natural Gas						
U.S. Dry Gas Production	Tcf/year	21.57	23.49	21.50	19.98	21.42
Shale Gas Production (e)	Tcf/year	4.87	8.21	7.35	4.51	2.97
Net Imports of Natural Gas	Tcf/year	2.56	1.90	2.14	2.51	1.86
LNG	Tcf/year	0.43	0.50	1.41	1.50	1.36
Total	Tcf/year	24.20	25.39	23.70	22.61	23.34
Unproved Lower 48 Gas Resources (j)	Tcf		na	na	1,586	1,367
Unproved Shale Gas Resources (j)	Tcf		827	652	347	267
Completion of Alaskan Gas Pipeline	year		post 2035	2030	2023	2020
Consumption of Natural Gas						
Total	Tcf/year	24.13	25.34	23.72	22.63	23.46
In Electric Power Generation (c)	Tcf/year	7.38	6.84	6.41	5.66	6.54
Total U.S. Energy Consumption (e)	Quads/year	97.7	104.9	105.3	105.0	105.4
Prices of Energy						
Natural Gas at the Henry Hub	$/MMBtu (b)	4.41	5.14	6.06	6.83	7.80
Imported Low S Light Crude Oil	$/bbl (b)	(f) 76.56	110.11	101.44	100.87	121.27
Net Generation of Electricity by Fuel Type (d)		(h)				
Total	billion Kwh	4,120	4,453	4,559	4,525	4,618
Coal	billion Kwh	1,851	1,907	2,046	2,093	2,156
Natural Gas	billion Kwh	982	1,002	876	767	898
Nuclear Power	billion Kwh	807	877	883	883	862
Renewables, Incl hydro	billion Kwh	425	608	683	713	617
Macroeconomic Indicators		**Year 2009**				
Real Gross Domestic Product	billion 2005 $	12,881	17,421			
Real Gross Domestic Product	billion 2000$			15,440	15,416	15,876
Total Energy Intensity (i)	Mbtu/2005 $	7.35	6.02			
Total Energy Intensity	Mbtu/2000$			6.82	6.81	6.79

(a) Sources: EIA Annual Energy Outlook 2009, 2010 and 2011.
(b) Prices in 2011 $, except macroeconomic indicators.
(c) Includes gas consumption in plants that sell to the public but not the end-use that geneates heat and electricity.
(d) Includes generation in utiities, plants producing heat and power for sale and end-use production of heat and power.
(e) Source for shale gas production in 2010: EIA Annual Energy Outlook 2011 early release table 14.
(f) Source for 2010: EIA Petroleum Marketing Monthly, March 2011, Table 1 Refiners cost of imported crude oil.
(g) The AEO 2009 HH price projection was adopted as the AESC 2009 Henry Hub base case price forecast for years after 2011.
(h) Source for 2010: EIA Electric Power Monthly, March 2011
(i) Total energy intensity is thousands of Btu per dollar of real GDP, which is valued at a specified real $.
(j) Estimate as of date of forecast preparation

Based upon our review of those cases we chose the AEO 2010 High Shale case as the source of our long-term forecast of Henry Hub prices.

- The AEO 2010 High Shale case is based upon an estimate of shale gas resources consistent with AEO 2011 Reference Case, as shown in Exhibit 3-7.
- The AEO 2010 High Shale case projection of Henry Hub prices is consistent with our estimates of the full-cycle costs of shale gas as shown in Exhibit 3-6. In contrast, as noted, the AEO 2011 Reference case forecast seemed particularly low relative to the full-cycle cost.
- Documentation for the AEO 2010 High Shale case was available in February and March 2011, when we were preparing our initial projections. However, our review of the full AEO 2011 documentation, which became available in late April 2011, supports our decisions to rely on the AEO 2010 High Shale Case. The estimate of the marginal cost of shale gas implicit in the various AEO 2011 cases are significantly less that our estimate of the full-cycle, all-in cost of finding, developing and producing shale gas.

3.5. Forecast of Annual Natural Gas Prices at the Henry Hub

This section presents our base case as well as our High Price and Low Price cases. The High and Low Price cases represent the possible variation in expected annual average Henry Hub gas prices recognizing the uncertainty associated with all long-term forecasts. These prices are not intended to address the issue of price volatility, which is discussed in the next section.

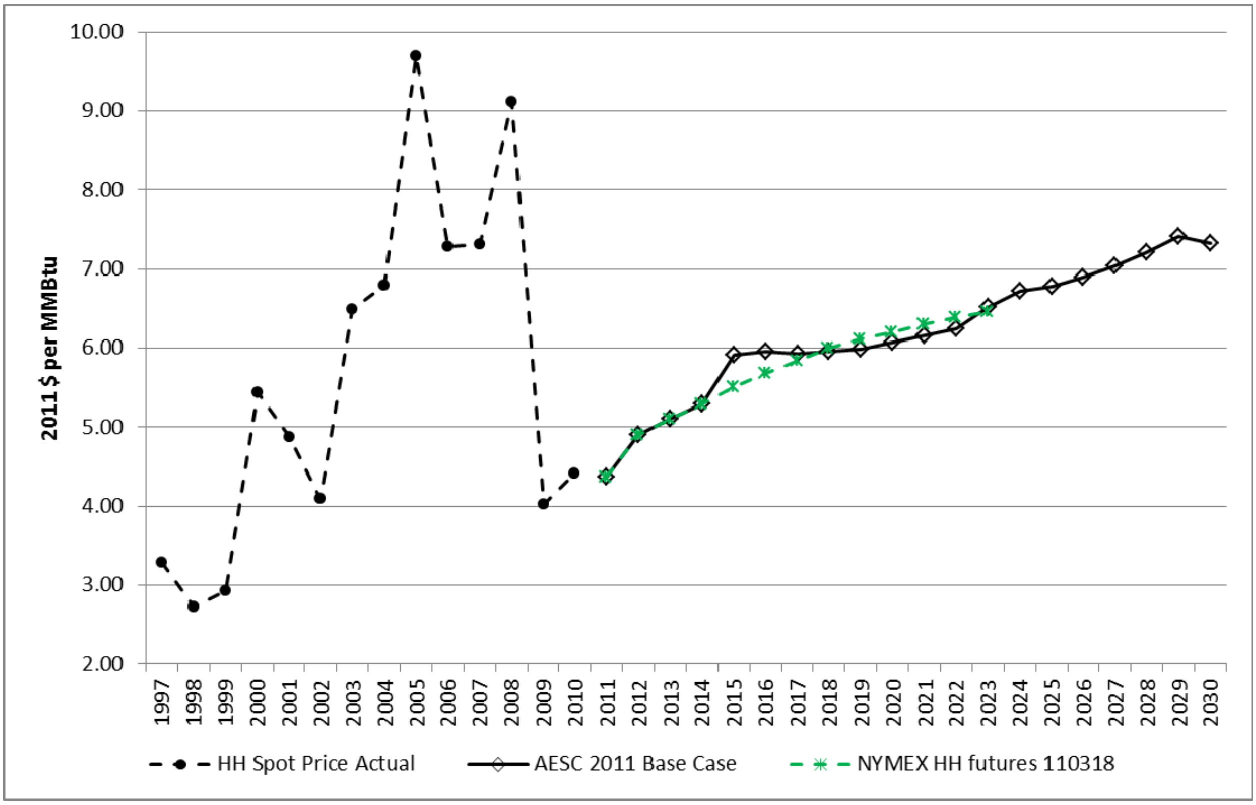
3.5.1. Base Case Forecast of Henry Hub prices

Based on the above presentation of our analyses, the AESC 2011 Base Forecast uses NYMEX futures, as of March 18, 2011, through 2014 and the AEO 2010 High Shale case from 2015 onward.

Comparisons to Historical Prices and other Forecasts

Exhibit 3-8 shows the AESC 2011 Base case annual Henry Hub natural gas price forecast and the annual average actual Henry Hub gas prices since 1997 through 2010. The forecast shows gas prices rising from current low levels to about $6.00 per MMBtu by 2015, holding flat and then rising again. The forecast rise in prices over the next few years is consistent with current prices being below our estimated full-cycle costs of finding and producing natural gas from shale. There will continue to be technological improvements and improvements in drilling and completion practices, which should tend to reduce the costs of finding and producing gas. However, producers, especially when gas prices are low, tend to produce from fields where costs are low and/or reserves are high, i.e. the best areas, before moving to fields where costs are higher and/or reserves are lower.

Exhibit 3-8: Actual, AESC 2011 forecast and NYMEX Futures Henry Hub prices



Thus, we expect prices to rise in the long term as the best areas are depleted and production migrates to areas of higher cost and/or lower productivity.[67]

Exhibit 3-8 also indicates that the AESC 2011 Base case forecast and the NYMEX HH futures prices as of March 18, 2011 are very similar beyond 2014. Nonetheless we continue to believe that in the long-term a price forecast based on fundamentals, especially estimates of the full-cycle, all-in cost of natural gas, is a better price forecast than the out years of the futures prices.

The AESC 2011 Base Case forecast of Henry Hub prices for 2015 is approximately 10 % higher than the average projections of four other

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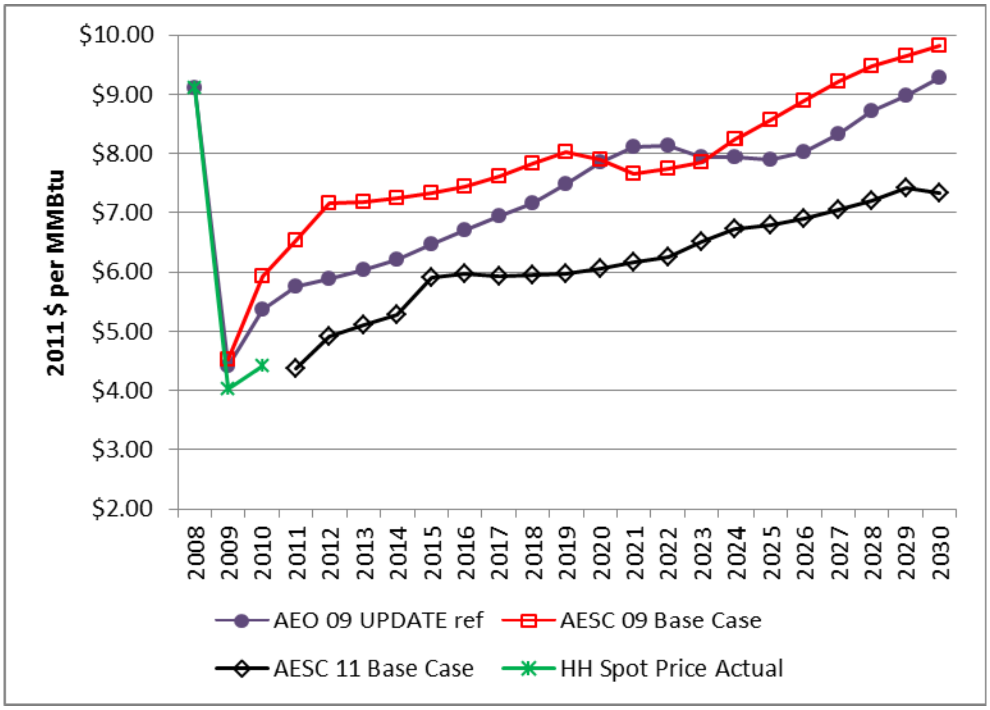
67 Vello Kuuskraa and Scott Stevens, "Lessons learned help optimize development" Oil & Gas Journal, October 5, 2009, page52.

organizations reported in AEO 2011, and approximately the same as their average forecast for 2025.[68]

3.5.1.1. Comparison to AESC 2009 Base Case

Exhibit 3-9 compares the AESC 2011 Base Case forecast with the AESC 2009 Base Case forecast and the AEO 2009 Update projection of annual Henry Hub gas prices. As can be seen the AESC 2011 forecast is considerably lower than the AESC 2009 forecast.

Exhibit 3-9: Comparison of Henry Hub Natural Gas Price Forecasts



The lower prices forecast in AESC 2011 is attributable to the remarkable progress that gas producers and service contractors have made in producing shale gas; in particular in being able to drill horizontal wells and the hydro fracturing of the shale to allow the gas trapped in the shale to travel to the well. Specifically we estimated in AESC 2009 (see pages 3-13 to 3-15, AESC 2009) that the full-cycle cost of shale gas was in the $6.50 to $8.00 per MMBtu range. For AESC 2011 we estimate the full-cycle cost of shale gas equates to about $5.50 per MMBtu at the Henry Hub.

68 Forecasts of IHSGI, EVA, DB and ICF reported in AEO 2011, pages 97 to 99.

3.5.2. High and Low Forecasts of Henry Hub Prices

The AESC 2011 Base Case forecast assumes a significant increase in shale gas reserves and production compared with AESC 2009. That assumption may be incorrect. The reserves may not be as large or economic to develop as assumed in that forecast. Alternatively, the reserves may be larger, or less expensive, to develop than assumed in that forecast. This section describes the AESC 2011 High Price case and Low Price gas case forecasts developed to reflect the range of uncertainty regarding projections of shale gas production quantities and costs. The sources of this uncertainty are discussed in more detail in Section 3.6.1.

The forecasts of the AESC 2011 Base case, High Price case, and Low Price case are shown in Exhibit 3-10.

Exhibit 3-10: Forecasts of AESC 2011 Henry Hub Natural Gas Prices: Base, High and Low

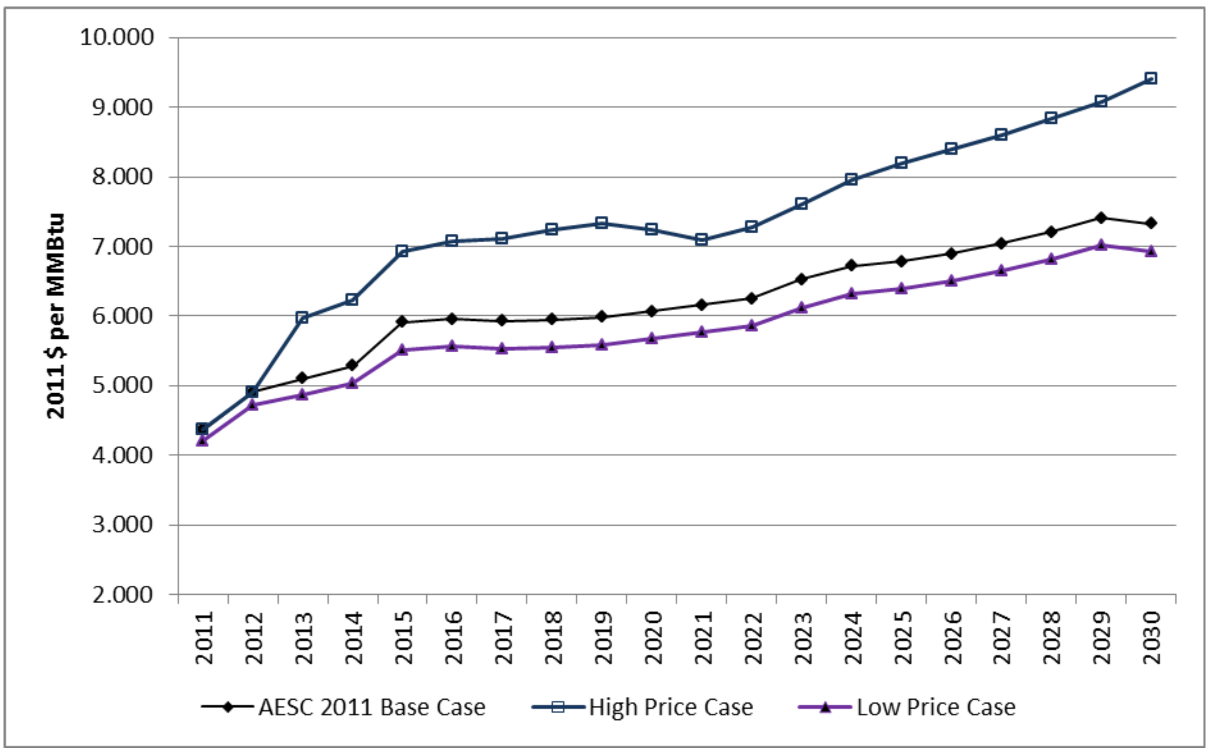


Exhibit 3-11 presents Henry Hub gas price projections based on four different assumptions regarding the future quantity of shale gas resources. (Shale gas resources are a measure of the quantity of estimated unproved, technically recoverable gas reserves.) The four shale gas resource cases are[69]:

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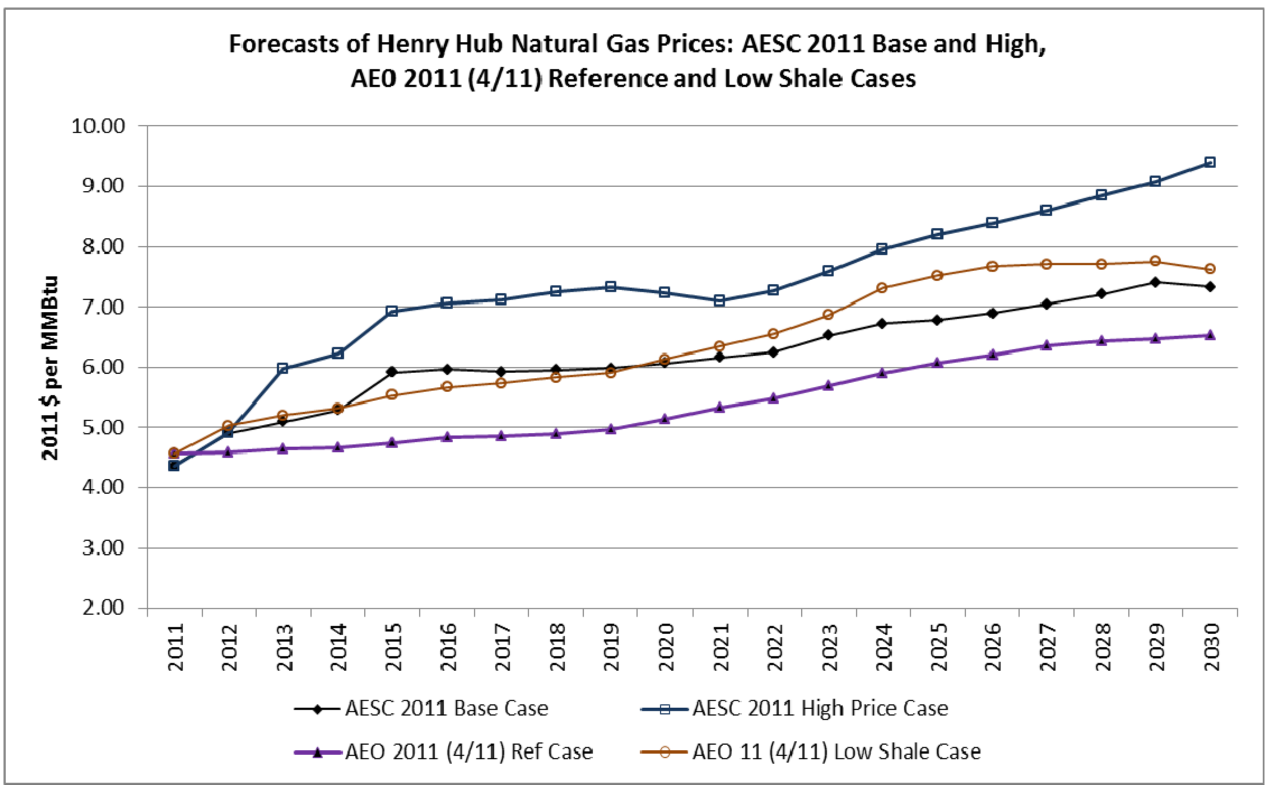
[69] Shale gas resource estimates are found in AEO 2011 report page 38 and AEO 2010 report page 41.

- 347 Tcf, AESC 2011 High Price Case, (AEO 2010 Slow Technology case);
- 423 Tcf, AEO 2011 Low Shale Recovery case
- 652 Tcf, AESC 2011 Base Case (AEO 2010 High Shale Gas Resource case); and
- 827 Tcf, AEO 2011 Reference case.

As noted earlier, the AESC 2011 Base Case is based on more conservative assumptions for shale gas production and cost than the AE0 2011 Reference Case. First, the AESC 2011 Base Case assumes a lower quantity of shale gas resources, at 652 Tcf versus 827 Tcf. Second, the AESC 2011 Base Case projects Henry Hub gas prices that are $0.70 to $1.10 per MMBtu higher than the AEO 2011 Reference Case starting in 2015. These higher prices appear to be due to the lower shale gas resource and higher drilling costs than assumed in that case. In confirmation of this note that the AEO 2011 Low Shale Recovery case, with an estimated shale gas resource 37 percent less than in the AESC 2011 Base case, has prices which are very similar to AESC 2011 Base case for the next 10 years out to 2022.

Exhibit 3-11: Comparison of AESC 2011 and AEO 2011 Henry Hub Gas Prices for Different Estimates of the Shale Gas Resource



3.5.3. AESC 2011 High Price Case

The AESC 2011 High Price case reflects a future in which access to shale gas resources is 47 percent less than the AESC 2011 Base Case and in which the costs of finding, development and production of the available resources are higher than in the AESC Base Case.

The AESC High Price Case is drawn from the AEO 2010 Slow Oil & Gas Technology case. That AEO 2010 case assumes shale gas resources of 347 Tcf rather than the 652 Tcf assumed in the AESC 2011 Base Case forecast. In addition the AEO 2010 slow technology case assumes that technology will be adopted at 50 percent of the rate assumed in the AESC Base case. These two assumptions represent a much lower ability to produce shale gas. For example the AESC 2011 High Price case assumes shale gas production of 4.14 Tcf in 2020 compared with 7.35 Tcf for the AESC 2011 Base case. The AESC 2011 High Price case represents a reasonable upper boundary on the long-run, average price of gas in the future given current views on natural gas supply and demand.

The AESC 2011 High Price represents the impact of cutting the quantity of shale gas resources that can be developed nearly in half relative to the AESC 2011 Base case and of raising the cost of shale gas development in the remaining areas relative to the costs in the AESC Base Case. One possible cause of such an impact would be a future in which the quantity of technically and economically recoverable shale gas reserves proves to be dramatically less than current estimates, the potential for new technological improvements and cost reductions to be achieved proves to be much less than current estimates, that more stringent regulations are imposed upon shale gas development and production, or some combination of those possible factors,

To be consistent with using the NYMEX gas futures prices as the basis of the AESC 2011 Base Case forecast for the years 2011 – 2014, the AESC 2011 High Price Case uses the NYMEX for 2011 and 2012. For 2013 and 2014 we compute the difference in the projected Henry Hub gas price between AEO 2010 Slow Technology case and the AEO 2010 High Shale case and add that difference to the NYMEX futures prices for 2013 and 2014. From 2015 onward our High Price case forecast is the price projected in the AEO 2010 Slow Technology case.

3.5.4. AESC 2011 Low Price Case

The AESC 2011 Low Price case assumes a decrease in finding, development and production costs for natural gas due to developments in oil and gas technology 50% more rapid than in the Base Case. The result is a lower Henry Hub gas price as technology reduces costs and increases the exploitation of gas reservoirs.

To develop the AESC 2011 Low Price Case we begin by estimating the effect of the more rapid technology on Henry Hub prices. We estimate this effect to be a reduction in Henry Hub gas prices equal to the difference between Henry Hub gas prices under the AEO 2010 Reference Case and Henry Hub prices under the AEO 2010 rapid technology case. The difference between the Henry Hub prices in those cases reflects the impact of more rapid technological development because all other parameters of those two cases are the same; in particular these two cases assume the same quantity of shale gas resources.

In the next step we develop the AESC 2011 Low Price case forecast by applying the reductions in price caused by more rapid technology as calculated in step one to the AESC 2011 Base Case forecast. For years 2011 through 2014 the AESC Low Price case each year is the AESC Base case forecast in that year less the rapid technology reduction for that year estimated in step one. For years 2015 through 2030 the AESC Low Price case each year is the AESC Base case forecast in that year less the average price reduction between the AEO 2010 reference case and the AEO 2010 rapid technology case over the period 2015 through 2030. We use the long-term average instead of the corresponding yearly reductions during that period because the difference in prices between the two cases in years 2023 to 29 seems to be caused by the EIA model bringing on the Alaska Natural Gas pipeline in the AEO 2010 reference case but not in the AEO 2010 rapid technology case. As a consequence the price differences represent the impact of more factors than just the difference between rapid technology development and Reference Case technology development.

3.6. Special Issues: Uncertainty Regarding Shale Gas Projections and Volatility of gas prices

3.6.1. Uncertainty Regarding Shale Gas Projections

There is considerable uncertainty regarding projections of shale gas production quantities and costs, as described below. Given the uncertainty associated with projections of shale gas resource availability, production quantities, regulations, and costs, there is certainly a possibility that material changes in the long-term outlook for shale gas production and cost may occur after the completion of AESC 2011 and before the initiation of AESC 2013. Those material changes might be driven by public developments such as significant revisions to public geological analyses; a legislative body, policy agency, or regulatory agency identifying specific changes in the regulation of hydraulic fracturing; published estimates of the costs associated with regulatory changes; or changes in natural gas market prices. In the event of such public developments, members of the Study Group may choose to determine if the AESC 2011 Reference Case and High Gas Price Case projections of natural gas prices are still suitable for use in energy efficiency cost-effectiveness analyses. If they determine that neither of those projections is within a range of reasonableness in light of the public developments, the members of the Study Group should consider revising the natural gas price forecast and the avoided costs.

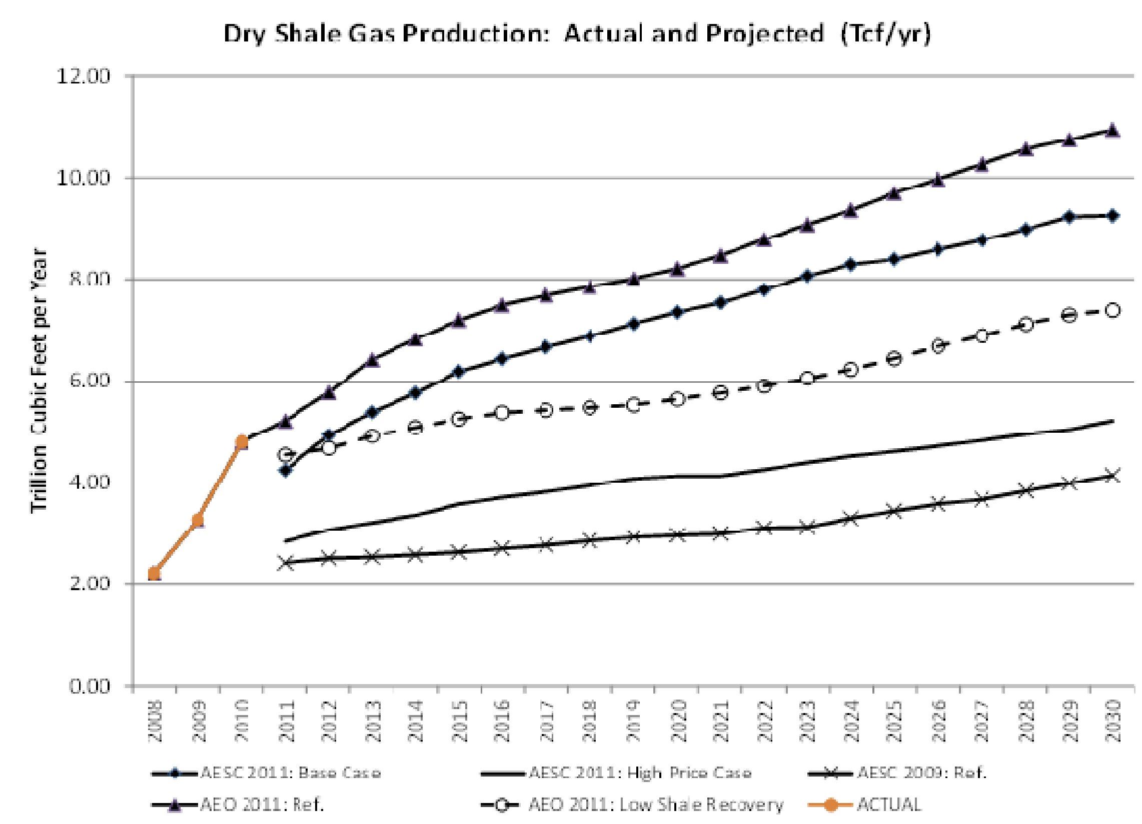
3.6.1.1. Technical Uncertainty

The first area of uncertainty relates to the estimates of technically recoverable quantities of shale gas and the costs of recovering those volumes. AEO 2011 acknowledges this uncertainty and identifies several factors that could tend to result in less production or higher costs under some scenarios, or more production and lower costs under other scenarios.[70] These factors include limited reliable data on long-term production profiles and ultimate gas recovery rates, use of production rates from portions of certain formations to infer the productive potential of the entire formation and the possibility that technical advances could reduce drilling and completion costs.

Exhibit 3-12 presents actual levels of annual shale gas production from 2008 through 2010 as well as the projected production underlying the various cases we examined.

[70] AEO 2011 report pages 37-38.

Exhibit 3-12: Dry Shale Gas Production: Actual and Projected (Tcf/year)



3.6.1.2. Regulatory Uncertainty

A second area of uncertainty is the potential impact of changes in the future regulation of shale gas development; in particular changes in the future regulation of hydraulic fracturing. Concerns have been raised regarding the need for additional regulation of hydraulic fracturing in order to minimize its environmental impacts on groundwater, surface water, and air emissions and the potential impact of such changes in regulation on shale gas production quantities and cost. However, AEO projections do not consider potential impacts of pending or proposed legislation but instead are generally based upon the Federal, State, and local laws and regulations in effect as of the date the AEO is prepared. Therefore, we reviewed the most recent literature regarding potential changes in regulation of hydraulic fracturing in order to determine whether we should include an explicit adjustment for such changes in the development of our Base Case or High Price Case forecasts.

Our review, summarized below, demonstrates that there is certainly considerable debate surrounding future changes to the regulation of hydraulic fracturing of shale gas. A June 2011 report by the International Energy Agency notes these issues and states that they must be, and can be, addressed[71]. However, other than the disclosure of chemicals in fracturing fluid, our review of the literature did not find any public projections of specific changes in existing Federal, state and local regulations, including scope and timing, from which to develop a credible estimate of a material impact on the cost of shale gas production.[72]

History. Hydraulic fracturing of oil and gas wells reportedly started in 1949 in the United States. Since then many thousands of wells have been hydraulically fractured.[73] All aspects of oil and gas well drilling, development and production, including hydraulic fracturing, are regulated;

> "There exists an extensive framework of federal, state, and local requirements designed to manage virtually every aspect of the natural gas development process. These regulatory efforts are primarily led by state agencies and include such things as ensuring conservation of gas resources, prevention of waste, and protection of the rights of both surface and mineral owners while protecting the environment. As part of their environmental protection mission, state agencies are responsible for safeguarding public and private water supplies, preserving air quality, addressing safety, and ensuring that wastes from drilling and production are properly contained and disposed of."[74]

3.6.1.3. Potential Impact on Water Supply

One of the major concerns about hydraulic fracturing is the possibility that fracturing fluids might flow into and contaminate water supplies. For example:

- The US EPA is studying the impacts of hydraulic fracturing used in shale gas wells with an initial set of findings expected at the end of 2012 and a final report in 2014.
- New York State had moratorium on shale gas drilling while it evaluated the impacts of hydraulic fracturing.

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71 ___. *Are We Entering A Golden Age of Gas.* International Energy Agency. June 2011.

72 Unlike expectations regarding future Federal regulation of CO_2 emissions, there are not dozens of projections available for parties to analyze and upon which parties can make an informed judgment.

73 Halliburton claims over one million wells have been successfully fractured in the U.S. www.halliburton.com at its overview page in its description of fracturing as one type of stimulation service.

74 DOE, Office of Fossil Energy, Modern Shale Gas Development in the United States: A Primer, April 2009 (DOE primer 2009) The regulatory framework and environmental considerations of shale gas wells are reviewed in this report pages 25 - 76

- Two reports by researchers at Duke University maintain that hydraulic fracturing in the Northeast is contaminating drinking water and should be regulated under the Safe Water Drinking Act.[75]
- The Administrator of the EPA, Lisa P. Jackson, in testimony on May 24, 2011 before the U.S. House Oversight and Government Reform Committee said that she is "…not aware of any proven case where the fracking process itself has affected water."[76]
- An MIT study published in June 2011 found no evidence that fracturing fluids were contaminating freshwater zones.[77]

Another concern has been the quantity of water used in hydraulic fracturing of gas shale. The MIT study estimates that water usage is small compared to other uses of water. (MIT gas 2011, page 44)

3.6.1.4. Air Emissions

Another area of concern is the emissions of methane and nitrogen oxides associated with shale gas production. We found no quantitative estimates of the quantity of NO_x emissions associated with shale gas development and conflicting estimates of methane emissions. For example:

- A study by Cornell University Professor Robert Howarth estimates that methane released into the atmosphere in shale gas development and subsequent transportation can generate over a 20-year horizon a greenhouse gas (GHG) footprint at least 20 percent greater than for coal when expressed per quantity of energy available during combustion.[78]
- A Wood Mackenzie report states that the Howarth study overestimated methane emissions by up to 90 percent by failing to consider that methane emissions can be flared and that reduced emission completions (RECs) are increasingly used in shale gas development including the Barnett shale, Fayetteville shale and Piceance tight gas play.[79]

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[75] Osborn, Stephen et al. *Methane Contamination of Drinking Water Accompanying Gas-well drilling and Hydraulic Fracturing.* and *Research and Policy Recommendations for Hydraulic Fracturing and Shale Gas Extraction.*

[76] Video of the testimony accessed via the committee website and Natural Gas Intelligence, Vol. 30, No. 39, May 30, 2011, page 3

[77] MIT Energy Initiative, The Future of Natural Gas, July 2011, page 7. (MIT gas 2011)

[78] Robert A, Howarth, Renee Santoro and Anthony Ingraffea, "Methane and the greenhouse-gas footprint of natural gas from shale formations", Climatic Change Letters, May 2011, page 9. (Howarth 2011)

[79] Foster Natural Gas Report, "Wood Mackenzie report addresses perceived gaps in Cornell study of methane emissions associated with flowback gas", Report No. 2847, May 13, 2011, page 14. (Wood Mackenzie 2011)

3.6.1.5. Disclosure of Chemicals in Fracturing Fluids

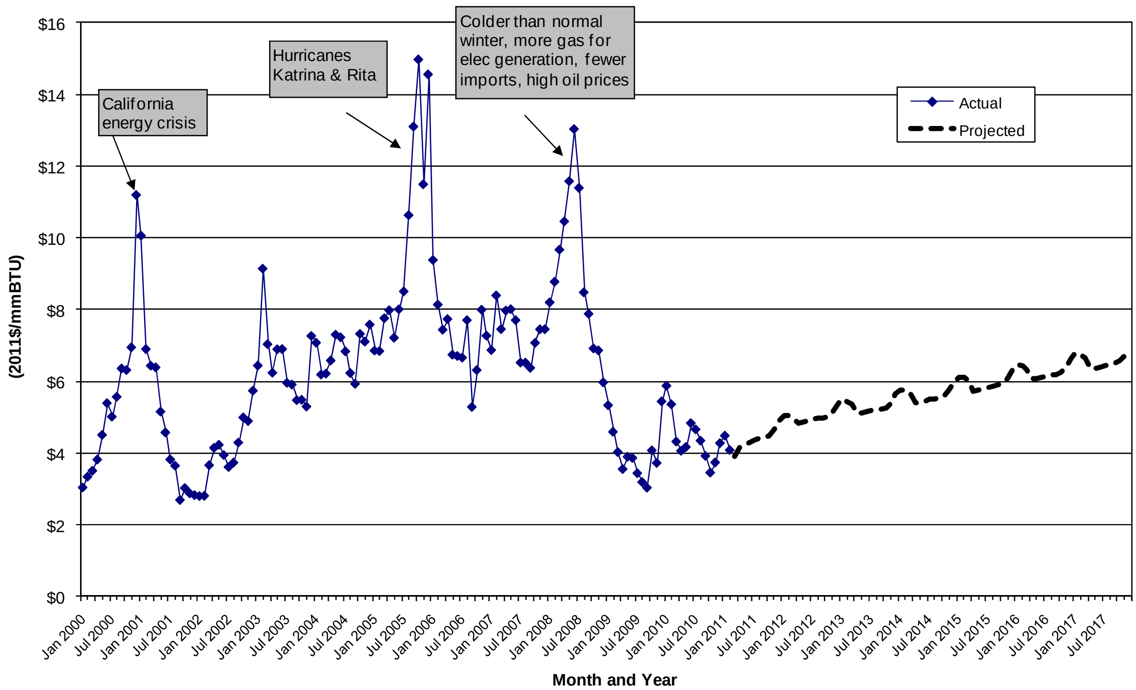
Also being discussed is the need for hydraulic fracturing operations to disclose the chemicals that are in the fracturing fluid. It has been estimated that various chemicals make up 0.5 percent to two percent of the fracturing fluid and the remainder is water and sand. (DOE primer 2009, page 61) On June 17, 2011 the Governor of Texas signed into law a requirement that companies make public the chemicals used on every hydraulic fracturing job: a requirement supported by the industry.[80] We believe that the chemical disclosure requirement will become widespread among the states in the US. It does not appear that the disclosure requirement will have a material effect upon the availability and cost of developing shale gas.

3.6.2. Representation of Volatility in Henry Hub Prices

Volatility is a measure of the randomness of variations in prices over time as affected by short-term factors such as extreme temperatures, hurricanes, supply systems disruptions, etc. It is not a measure of the underlying trend in the price over the long-term. Our forecasts of Henry Hub prices under the Base, high, and low cases provide projections of expected average natural-gas price in any year. Actual gas prices are volatile and in any future month, week or day will vary around the expected annual average prices forecast in each of those three cases. We have not attempted to forecast the actual monthly or weekly prices that would reflect historic price volatility primarily because we are forecasting prices used to evaluate avoided costs in the long term. Our analyses indicate that the levelized price of gas over the long term would not be materially different if one estimated increases from an occasional one-to-three-day price spike during a cold snap or even the type of several month gas price increases following Hurricane Katrina in the fall of 2005. For example, monthly Henry Hub prices were very volatile from 2000 through 2010, ranging from less than $4.00/MMbtu to over $14/MMbtu. See Exhibit 3-13. However, the levelized average annual cost over that period was $5.80/MMBtu. If one substitutes annual average prices for certain months with very high prices, such as the four months affected by Hurricanes Katrina and Rita, and the three month price spike in mid-2008, the levelized price over the entire eleven year period remains very similar at $5.65/MMBtu.

[80] Wall Street Journal, "'Fracking' Disclosure to Rise", June 20, 2011, page B1.

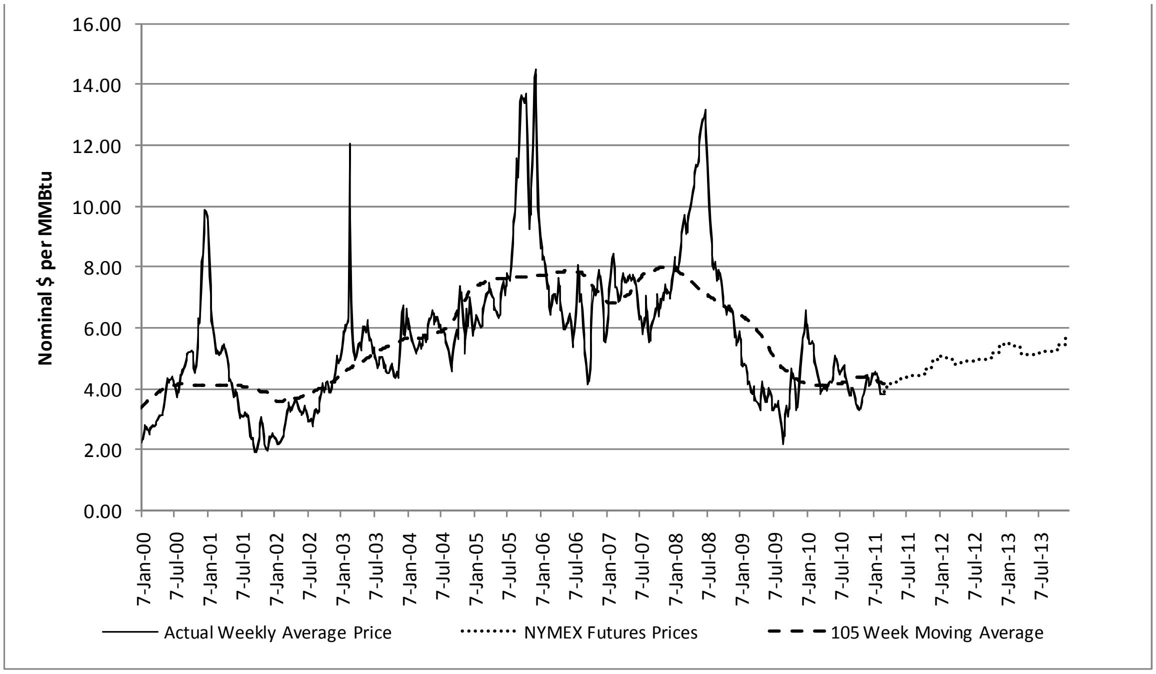
Exhibit 3-13: Monthly Henry Hub Prices, Historical (EIA) and Projected (2011 Dollars per MMBtu)



The range of volatility in weekly Henry Hub gas prices is even higher. See Exhibit 3-14.

Exhibit 3-14 shows the weekly average of the daily spot price of natural gas at the Henry Hub from 2000 through March of 2011 and then monthly NYMEX gas futures prices through December 2013. These prices are in nominal dollars; they have not been adjusted for inflation because this discussion of volatility does not require prices in real terms.

Exhibit 3-14: Henry Hub Average Weekly Natural-Gas Prices, Actual and Futures, Jan 2000 – Dec 2013



Price spikes and dips show price volatility. In New England and in other gas consuming areas there have been daily price spikes during very cold weather. In addition, natural-gas prices have increased for longer periods. The recent example of Hurricane Katrina in 2005 is illustrative, as follows.

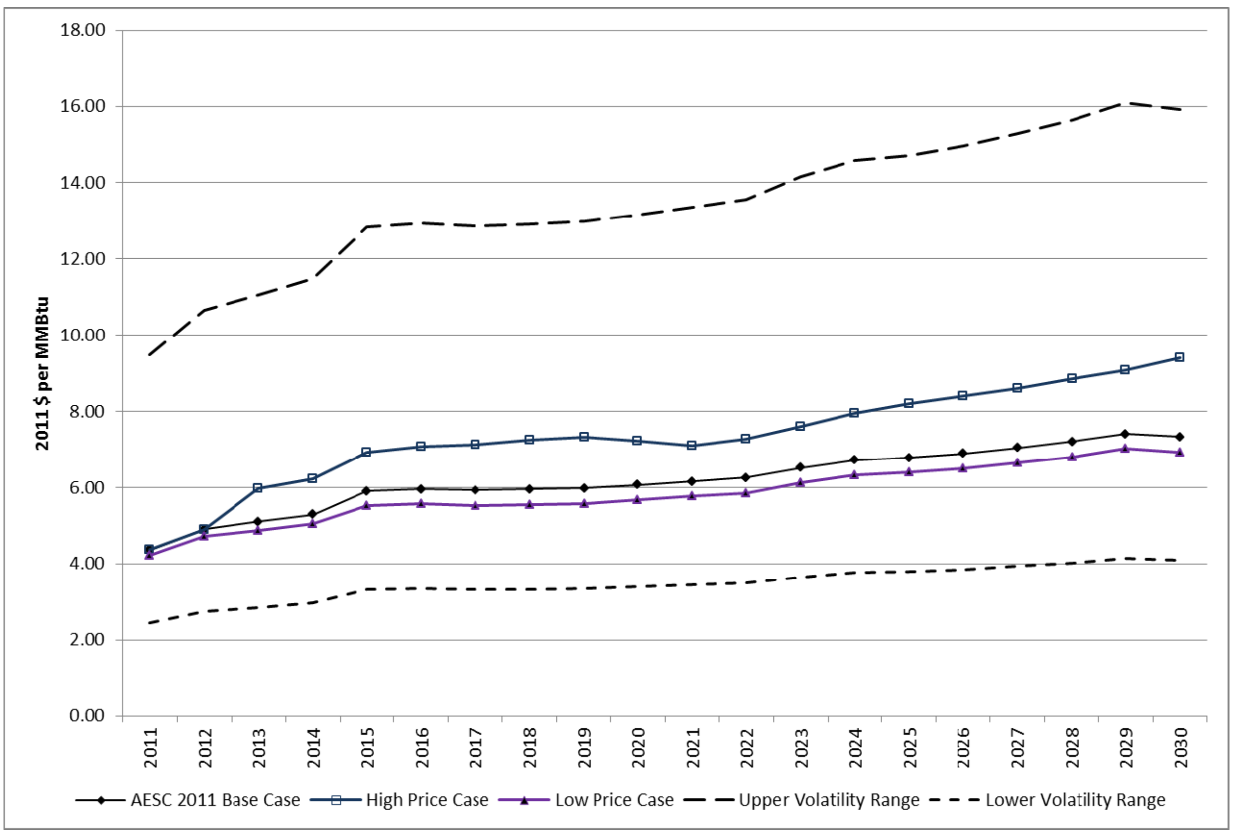
- On July 29 2005 the NYMEX gas futures contract for September 2005 delivery was priced at *$7.89* per MMBtu;
- On August 29 2005 Katrina hit the Gulf Coast;
- On December 13, 2005 the NYMEX January 2006 gas futures contract settlement price was *$15.38* per MMBtu;
- on March 1 2006, six months after Katrina struck the Gulf Coast, the April 2006 gas-futures contract was priced at *$6.73* per MMBtu;
- Subsequently 2006 experienced few hurricanes and on September 27 2006 the October 2006 gas futures contract closed at *$4.21* per MMBtu.

In this example a shock that removed 5 billion cubic feet per day of natural-gas supply produced a strong increase in prices. However, prices quickly reversed to more-typical levels and in less than a year gas futures price fell (temporarily) to a level less than one-third of the peak of December 2005. We expect such shocks and gas price volatility to continue periodically in the future. Nonetheless, the

AESC 2011 Base gas price forecast provides a reasonable estimate of average or expected Henry Hub gas prices for the purposes of this study.

We quantify Henry Hub–price volatility as follows. First we find a 105-week moving average of the weekly prices centered on the current week. This 105-week moving average is the average of the 52 previous weeks of prices, the price of the instant week, and the prices from the 52 weeks following. Then for each week we calculate the ratio of the current price to the 105 week average price. There have been four peak prices during this period of 2000 to March 2011 and the average ratio of the peak price to the 105-week moving average price as of that week is 2.17. Similarly, there were four downside bottoms in price and the average ratio of the four bottom prices is 0.56 of the 105-week moving average price. These results indicate that the actual average of daily prices in any week could range between 0.59 and 2.19 of the long-term average of Henry Hub daily prices. Exhibit 3-15 depicts this range. The range of price volatility is large, especially compared with the upper and lower range of forecast average prices.

Exhibit 3-15: Range of Potential Weekly Price Volatility versus the Forecast Base Case Annual Average Henry Hub Natural Gas Price



3.7. Forecast of Wholesale Natural-Gas Prices in New England

The forecasts of wholesale monthly natural-gas prices for New England as a region, and for each state, are presented in Exhibit 3-17.

The forecast wholesale natural-gas commodity prices each month comprise the forecast monthly commodity price at the Henry Hub plus the forecast monthly basis differential for the relevant market hub(s) in New England. Our forecasts are based on Henry Hub prices plus the following components:

- *Massachusetts, New Hampshire and Maine*–Basis differential to Tennessee Gas Pipeline (TGP) Zone 6;
- *Connecticut and Rhode Island*–Basis differential to Algonquin Gas Transmission (AGT);
- *New England region excluding Vermont*–Average of basis differential to Tennessee Gas Pipeline (TGP) Zone 6 and to Algonquin Gas Transmission (AGT).

We do not forecast a wholesale natural-gas commodity price for Vermont because there is no liquid spot market for gas in that state.

3.7.1. Forecast by Market Hub and State

Like AESC 2009, we assume that the market hubs on Tennessee Gas Pipeline (TGP) Zone 6 and Algonquin Gas Transmission (AGT) represented the majority of gas traded in wholesale markets in New England.

For AESC 2011 as in AESC 2007 and AESC 2009, we calculate historical average basis differential ratios for each of those two market hubs as a ratio of the monthly Henry Hub price and the monthly price reported at the hub. The ratios are calculated for each month over 11 years, January 2000 through December 2010. The average monthly basis-differential ratios for TGP Zone 6 and AGT is then applied to the monthly forecast of Henry Hub natural-gas prices to develop monthly prices for TGP Zone 6 and AGT over the forecast period.

The AESC 2011 average monthly basis differentials are within one percent of the AESC 2009 ratios. See Exhibit 3-16 below.

Exhibit 3-16: Monthly Basis-Differential Ratios (to Henry Hub): AESC 2011 vs. AESC 2009

	AESC 2009			AESC 2011		
	Tenn. Zone 6 Dlvd Mo	*Algonquin CG Mo*	*Average of Tenn. 6 and Algonquin*	*Tenn. Zone 6 Dlvd Mo*	*Algonquin CG Mo*	*Average of Tenn. 6 and Algonquin*
Jan	1.27	1.37	1.32	1.38	1.41	1.40
Feb	1.36	1.41	1.39	1.29	1.43	1.36
Mar	1.13	1.14	1.14	1.12	1.14	1.13
Apr	1.08	1.09	1.09	1.10	1.10	1.10
May	1.08	1.09	1.09	1.09	1.09	1.09
Jun	1.08	1.09	1.09	1.09	1.09	1.09
Jul	1.09	1.10	1.09	1.03	1.10	1.06
Aug	1.08	1.09	1.08	1.08	1.09	1.09
Sep	1.07	1.07	1.07	1.07	1.08	1.07
Oct	1.08	1.09	1.08	1.15	1.09	1.12
Nov	1.11	1.12	1.11	1.06	1.12	1.09
Dec	1.18	1.21	1.19	1.34	1.24	1.29
Average	**1.13**	**1.16**	**1.15**	**1.15**	**1.17**	**1.16**

The basis differential for New England gas market has changed little since AESC 2009, and the change was a very small increase.

3.7.2. Forecast by Region

The forecast of regional monthly spot prices, with the exception of Vermont, was calculated as the average of the forecasts for prices of spot gas delivered to market hubs TGP Zone 6 and AGT.

The average of forecast gas prices for these two zones is appropriate for several reasons. An analysis of spot gas prices delivered to TGP Zone 6 and AGT between January 2000 and March 2011shows no material difference between prices on the two pipelines in most months. This is not surprising. There is ample opportunity for price arbitrage between the two pipelines given the number of interconnections between the two and the number of participants buying and selling gas in the wholesale New England market every day. Were the price on these two pipelines to diverge by too much over a sustained time period, arbitrage would reduce the price difference. In addition, arbitration panels rely upon the average of these two price indices, TGP Zone 6 and AGT, to represent the market value of gas in New England for purposes of setting prices under gas supply contracts between gas producers and generating units.

The AESC 2011 forecasts of New England regional wholesale prices are shown in Exhibit 3-17.

Exhibit 3-17: Forecast Annual Average Wholesale Gas Commodity Prices in New England (2011 Dollar per MMBtu)

	Henry Hub	CT	RI	MA	NH	ME	New England (excluding VT)
2011	$ 4.37	$5.11	$5.11	$5.02	$5.02	$5.02	$5.07
2012	4.91	5.74	5.74	5.64	5.64	5.64	5.69
2013	5.10	5.97	5.97	5.86	5.86	5.86	5.92
2014	5.29	6.19	6.19	6.08	6.08	6.08	6.13
2015	5.91	6.92	6.92	6.80	6.80	6.80	6.86
2016	5.96	6.97	6.97	6.85	6.85	6.85	6.91
2017	5.93	6.94	6.94	6.82	6.82	6.82	6.88
2018	5.95	6.96	6.96	6.84	6.84	6.84	6.90
2019	5.98	7.00	7.00	6.88	6.88	6.88	6.94
2020	6.06	7.09	7.09	6.97	6.97	6.97	7.03
2021	6.16	7.20	7.20	7.08	7.08	7.08	7.14
2022	6.25	7.31	7.31	7.19	7.19	7.19	7.25
2023	6.52	7.63	7.63	7.50	7.50	7.50	7.56
2024	6.72	7.86	7.86	7.73	7.73	7.73	7.80
2025	6.78	7.94	7.94	7.80	7.80	7.80	7.87
2026	6.89	8.06	8.06	7.92	7.92	7.92	7.99

Notes

Connecticut and Rhode Island per basis-differential ratios to Algonquin market hub.

Massachusetts, Maine, and New Hampshire per basis differential ratio to Tennessee Zone 6 market hub.

New England, excluding Vermont, is based on the average basis-differential coefficient to Algonquin and Tennessee Zone 6.

3.7.3. Impact of New Regional Supplies on Wholesale Prices in New England

To date, increases in the quantity of supply to New England from eastern Canada and new LNG facilities have not led to major reductions in the price of gas in New England. Instead, those supplies have tended to displace gas that would otherwise have been delivered into the region from the Mid-Atlantic Region, a much larger market. In the future, as the sources of gas supply to the Eastern United States shift from the traditional Southwestern producing regions to new producing basins such as the Marcellus Shale and Rocky Mountain producing areas, the basis differential between New England and the Henry Hub may decline.

3.8. Forecast of Gas Prices for Electric Generation in New England

The price of natural gas for electric generation at any particular location can be represented as the wholesale Henry Hub price plus a basis differential representing the cost of delivering gas from the Henry Hub to that particular electric generating unit. The AESC 2011 forecast of prices of natural gas for electric generation in New England and New York thus comprises forecast monthly Henry Hub prices multiplied by a forecast differential. Because of the wide variation in natural-gas prices represented in the historical data we have normalized those relationships and presented the differentials as multipliers rather than adders. This section describes our derivation of the forecast differentials, presented below in Exhibit 3-18.

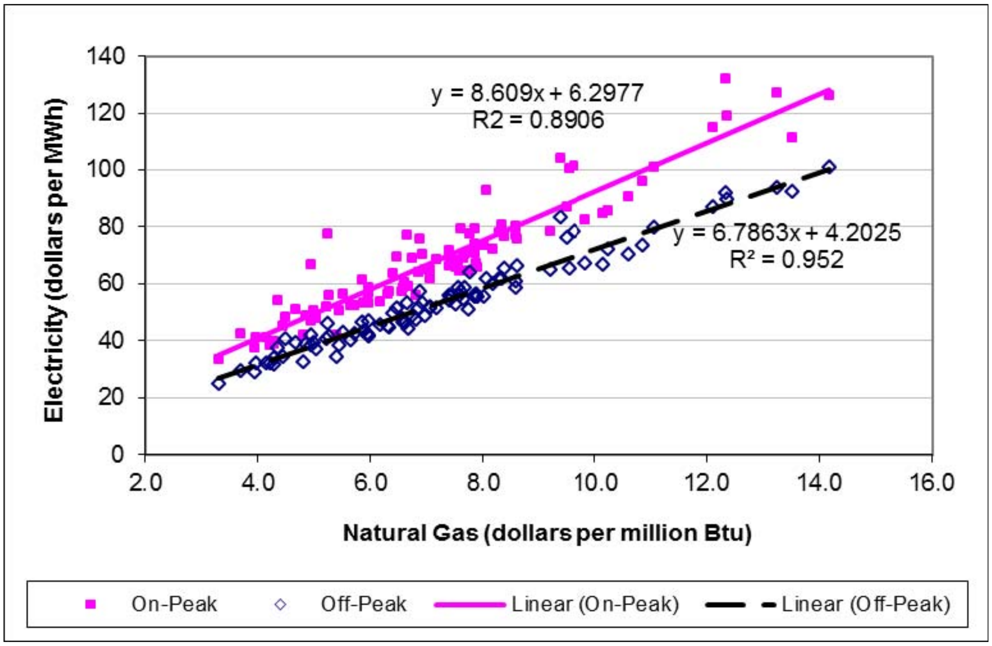
Exhibit 3-18: Monthly Natural-Gas Basis-Differential Ratios (to Henry Hub)

Month	New York	New England
January	1.357	1.354
February	1.258	1.239
March	1.240	1.187
April	1.181	1.141
May	1.145	1.107
June	1.145	1.085
July	1.218	1.126
August	1.209	1.132
September	1.164	1.086
October	1.191	1.104
November	1.235	1.136
December	1.324	1.297
Average	**1.222**	**1.166**

The forecast differentials are based on analysis of monthly prices for natural gas and electricity over the period 2003–2010. Based on the results from AESC 2009, we selected the historic monthly natural-gas prices paid by electric generators as reported to the EIA (2010c) and the corresponding monthly Henry Hub prices. From that we historic monthly differentials from the Henry Hub prices to provide the forecast of monthly prices for natural gas to electric generating units.

Exhibit 3-19 below presents a scatter plot of the monthly peak and off-period electricity prices versus the natural-gas prices as reported by EIA along with fitted trend lines. The coefficients on those lines represent average effective heat rates for the given periods.[81] For example, the implied heat rate for the peak period is 8,609 Btu/kWh representing a mix of less-efficient plants than for the off-peak period.

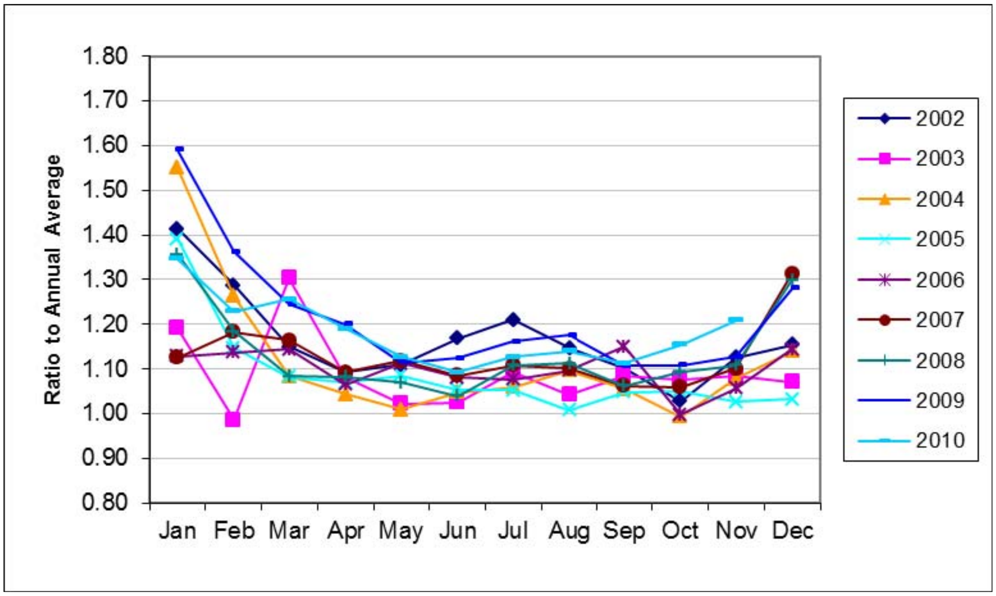
Exhibit 3-19: Monthly NE Electricity Prices vs. EIA Natural Gas Prices (2003–2010)



Based upon those analyses we developed the forecast monthly basis differentials presented in Exhibit 3-18 above. The forecast differential in each month is the average differential between the price reported to the EIA for that month and the monthly Henry Hub price over the nine-year period of 2002 to 2010. Exhibit 3-20 below shows those monthly ratios for New England. Although there are significant variations from one year to the next, there is also a consistent seasonal pattern reflecting much greater basis differentials for the winter heating season.

[81] Heat rate is a measure of the efficiency with which a generating unit converts fuel energy into electric energy. It is expressed in Btu of fuel burned per kWh of energy generated.

Exhibit 3-20: Ratio of Monthly Gas Prices Reported by New England Generating Units to Monthly Henry Hub Price



Chapter 4: Avoided Natural-Gas Costs

4.1. Introduction and Summary

The avoided cost of gas at a retail customer's meter consists of two components:

- The avoided cost of gas delivered into the distribution systems of New England local distribution companies (LDCs), and
- The avoided cost of delivering gas on those distribution systems ('retail margin').

These avoided costs vary primarily according to the shape of the gas load being avoided, with some additional variation by sector due to differences in distribution service costs by sector. We have calculated avoided costs by sector and load shape for three different regions—southern New England, northern and central New England, and Vermont—because of the differences in the cost of gas supply between those three areas.

Our projected values are presented in below in Exhibit 4-1 and Exhibit 4-2, alongside the corresponding values from AESC 2009. Greater detail on the avoided costs for AESC 2011 is shown later in Exhibits 4-13 through 4-16 for Southern New England and Northern and Central New England and in Appendix D for Vermont Gas Systems (VGS).

Exhibit 4-1: Summary Table Assuming Some Avoided Retail Margin

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS								
BY END USE: AESC 2009 AND AESC 2011								
ASSUMING SOME AVOIDABLE RETAIL MARGIN								
(2011$/Dekatherm except where indicated as 2009$/DT								
	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
2009 to 20119 change	-34.33%	-34.33%	-36.54%	-33.82%	-24.71%	-26.84%	-26.08%	-29.92%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
2009 to 2011 change	-32.57%	-32.57%	-35.03%	-32.38%	-25.64%	-28.37%	-27.41%	-29.99%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
2009 to 2011 change	-23.86%	-23.86%	-21.95%	-20.36%	-10.57%	-5.67%	-6.82%	-12.44%
(a) Factor to convert 2009$ to 2011 $		1.0186						
Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.								
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discoiunt rate of 2.465%.								

Exhibit 4-2: Summary Table Assuming No Avoided Retail Margin

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2009 AND AESC 2011
NO AVOIDABLE RETAIL MARGIN in AESC 2011 but is in AESC 2009
(2011$/Dekatherm except where indicated as 2009$/DT

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.04	7.04	7.81	7.57	7.04	7.81	7.57	7.57
2009 to 20119 change	-39.50%	-39.50%	-47.23%	-44.98%	-30.10%	-35.24%	-33.67%	-39.34%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	6.94	6.94	7.58	7.39	6.94	7.58	7.39	7.39
2009 to 2011 change	-37.32%	-37.32%	-45.04%	-42.77%	-32.01%	-38.26%	-36.37%	-39.70%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.06	7.06	8.63	8.16	7.06	8.63	8.16	8.16
2009 to 2011 change	-28.68%	-28.68%	-31.84%	-30.70%	-13.50%	-10.32%	-11.00%	-19.38%

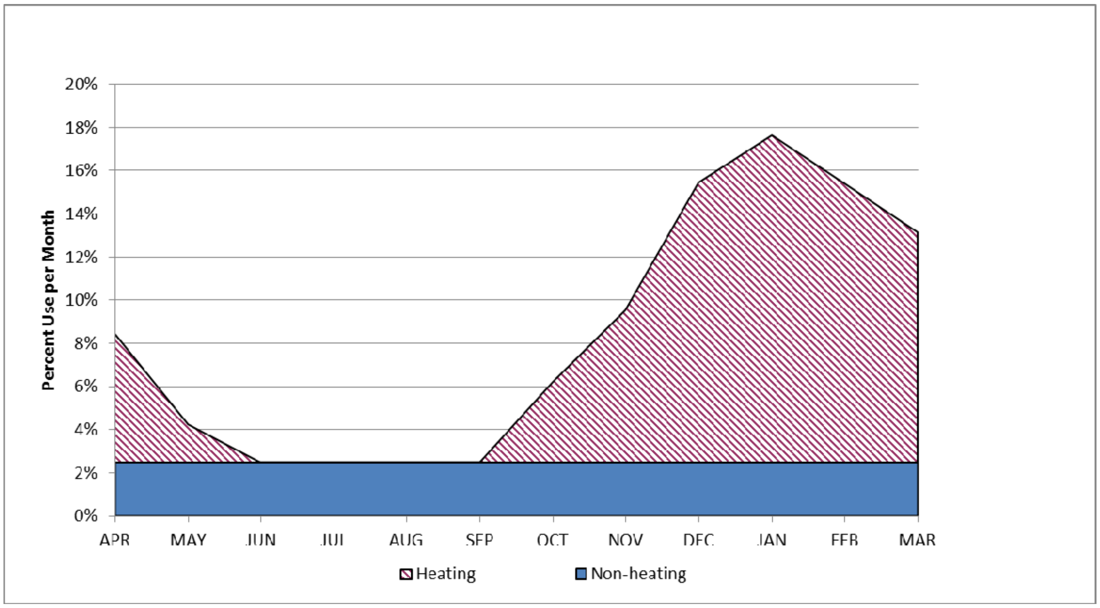
(a) Factor to convert 2009$ to 2011 $ 1.0186
Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discoiunt rate of 2.465%.

We project lower avoided costs for each end use compared with those projected in AESC 2009. Assuming that some retail margin is avoidable, Exhibit 4-1, the avoided costs to the end user ranges from 25 to 36 percent less than estimated in AESC 2009 for all states except Vermont. These lower avoided costs are due to a lower forecast Henry Hub price of gas and a lower estimate of the LDC retail margin that can be avoided. In Vermont the avoided costs to end users is 6 to 24 percent less. The lower price of gas at the Henry Hub and lower retail margin is offset by higher pipeline transportation and storage demand charges. When we assume that no LDC retail margin can be avoided in AESC 2011 but the avoided retail margin estimated in AESC 2009 is retained, Exhibit 4-2, the avoided cost is between 30 and 40 percent less than in estimated in AESC 2009 for states other than Vermont due to a lower forecast gas price and assuming that no retail margin is avoidable. In Vermont the avoided cost is about 10 to 32 percent less in AESC 2011 compared to AESC 2009 due to the higher pipeline and storage charges in AESC 2011.

4.2. Load Shape Is a Key Driver of Avoided Retail Gas Costs

The shape of the retail gas load being supplied has a major impact on the cost of that supply, and hence on the avoided cost of supply. The major end uses of gas by retail customers fall into two broad categories, heating and non-heating. Space-heating or winter temperature-sensitive end-uses represent the largest use in New England. As a result LDCs supply a load that has a significant swing from summer to winter and further temperature-driven variations by month throughout the winter. This variation in load by season, and month, by type of end-use are illustrated graphically in Exhibit 4-3.

Exhibit 4-3: End-Use-Load Profile

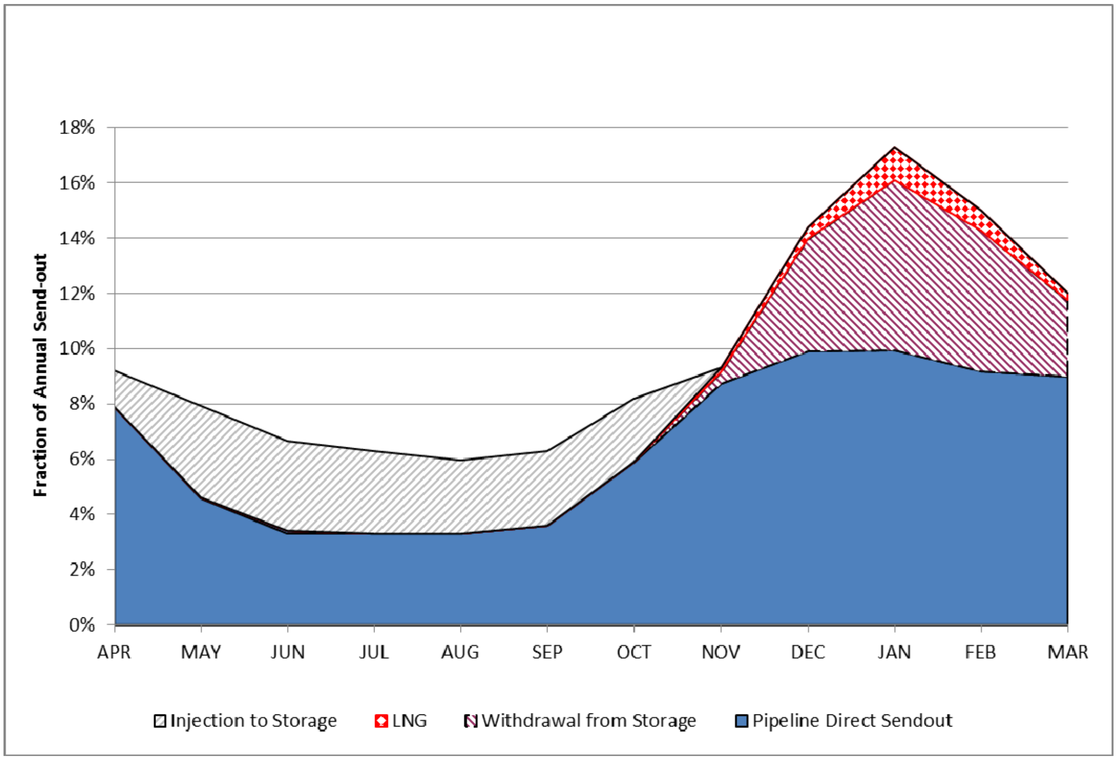


Because of the size of the gas load during the winter (defined as November through March in the gas industry) relative to the summer, and because the variation in daily load during winter months due to variation in daily temperatures, LDCs develop a portfolio of supplies in order to provide reliable service at reasonable cost over time. These portfolios comprise three major categories of delivery and storage resources: long-haul pipeline transportation, underground storage, and LNG or propane facilities.[82] We calculate the avoided cost of gas delivered into the distribution system of a New England local distribution company from the avoided cost of each resource in each month and the relative quantity of each resource that an LDC uses in each month.

[82]Local distribution companies acquire pipeline and storage services through contracts with pipeline companies whose terms and conditions are regulated by the Federal Energy Regulatory Commission.

Local distribution companies use their long-haul pipeline transportation to supply load directly in each month of the year. In addition, in summer months LDCs use a portion of that pipeline transportation capacity to deliver gas from producing areas for injection into underground storage, and sometimes for liquefaction and injection into LNG tanks.[83] In winter months LDCs meet customer load with gas delivered by pipeline directly from producing areas and from underground storage. LDCs use gas from LNG and propane facilities delivered directly into their distribution systems to meet daily peaking and seasonal requirements during the months of heaviest load, mostly December through February.[84] See Exhibit 4-4.

Exhibit 4-4: Representative New England Gas LDC Sendout by Source



Because LDCs incur fixed costs to hold pipeline transportation capacity, in the form of *demand charges* multiplied by their capacity entitlements, and because

[83]Local distribution companies may use some of their pipeline capacity to deliver gas in summer for injection into LNG tanks where there are liquefaction facilities on site.

[84] The data underlying the representative LDC sendout by source is the weighted average of the recent data supplied by Yankee Gas Systems, Connecticut Natural Gas Company, Columbia Gas of Massachusetts, NSTAR and National Grid (MA).

they use long-haul pipeline transportation capacity to provide supply in three major ways, we had to determine how best to allocate those fixed costs among the three transportation applications provided using this capacity.[85] The three transportation applications are transportation of gas supply for direct supply (send-out) in winter months, transportation of gas in summer months for injection to underground storage (and subsequent withdrawal in winter months) and transportation of gas for direct supply in summer months. Our analysis of how LDCs use their long-haul capacity for each application is presented in detail below.

Based upon our analysis of LDC use of long-haul capacity, our projection of avoided costs is based on an allocation of 100 percent of pipeline demand charges incurred in winter months to avoided costs in winter months. This allocation reflects LDC use of all of their capacity to provide direct supply in those months. Allocation of pipeline demand charges incurred in summer months is somewhat complex because LDCs use only approximately 75 percent of their capacity during those months based on information provided by LDCs. Of that 75 percent, they use about 46 percent to provide direct supply and about 29 percent to deliver gas for injection into storage. Based upon our analysis of LDC use of capacity in summer months:

- 25 percent of pipeline transportation demand charges incurred in summer months are allocated to avoided costs of winter months, corresponding to the approximately 25 percent of physical capacity not being used in the summer either to refill storage or provide direct supply;
- 29 percent of pipeline demand charges in summer months are allocated to the avoided costs of gas injected into storage. (All costs of gas injected into storage are allocated to avoided costs of winter months). This is the percentage of long-haul capacity LDCs use to transport gas for injection into underground storage in summer;
- 46 percent of pipeline demand charges in summer months are not allocated to avoided costs of summer months. This is the percentage of long-haul capacity LDCs use to provide direct supply in summer. Our analysis indicates that LDCs cannot avoid those costs.

[85] An LDC's fixed cost of capacity on a pipeline for a given month equals the pipeline's demand charge, expressed in dollars per month per dth/day of capacity, multiplied by the LDC's capacity entitlement or contract demand expressed in dth/day.

4.3. Avoided Cost of Gas to LDCs

This analysis estimates long-run avoided costs because energy efficiency improvements have long-term effects that can allow an LDC to avoid both short-run variable costs and some long-term fixed costs. We calculate the avoided cost of gas delivered into the distribution system of a New England LDC in two steps. First, we calculate the avoided cost of supply from each major resource in each month. Then we calculate the weighted average cost in each month based upon the relative quantity of each resource the LDC uses in each month. We also calculate a marginal cost (avoided cost) for the peak day.

4.3.1. Summary Results

Our estimated levelized avoided costs are 17 to 19 percent less than those of AESC 2009 mostly due to the forecasted lower cost of gas at the Henry Hub for AESC 2011 compared to AESC 2009 for the New England states other than Vermont. (See Exhibit 3-9 to compare the AESC 2009 and AESC 2011 base case Henry Hub natural gas price forecasts.) The pipeline rates were almost the same in each of the studies serving the states other than Vermont. See Exhibit 4-5. In Vermont the avoided cost of gas delivered at the city gate foe AESC 2011 is up to 6 percent greater in the winter than in AESC 2009 due to the much higher transportation and storage demand charges for AESC 2011 compared to AESC 2009. In the summer the AESC 2011 avoided cost is less that in AESC 2009 because the cost of gas is forecast to be less and there are no avoided transportation or storage demand charges in the summer.

Exhibit 4-5: Comparison of the Levelized (15 year) Avoided Cost of Gas Delivered to LDC's by Month from AESC 2009 to AESC 2011

COMPARISON OF THE LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO LDCs BY MONTH
FROM AESC 2009 AND AESC 2011

	Units		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual Average
SOUTHERN NEW ENGLAND: Gas Delivered via Texas Eastern and Algonquin Pipelines															
AESC 2009	2009$/DT	(a)	7.37	7.39	7.51	7.64	7.74	7.78	7.90	9.17	9.86	10.14	9.62	9.17	8.44
AESC 2009	2011$/DT	(b)	7.51	7.53	7.65	7.78	7.88	7.93	8.04	9.35	10.04	10.33	9.80	9.34	8.60
AESC 2011	2011$/DT	(c)	6.16	6.18	6.25	6.34	6.40	6.42	6.50	7.63	8.21	8.53	8.06	7.72	7.04
Percent Difference 2009 to 2011			-17.9%	-17.8%	-18.2%	-18.6%	-18.8%	-19.0%	-19.1%	-18.3%	-18.2%	-17.4%	-17.7%	-17.3%	-18.2%
NORTHERN and CENTRAL NEW ENGLAND: Gas Delivered via Tennessee Gas Pipeline															
AESC 2009	2009$/DT	(a)	7.35	7.36	7.48	7.61	7.71	7.75	7.87	8.94	9.41	9.69	9.23	8.83	8.27
AESC 2009	2011$/DT	(b)	7.48	7.50	7.62	7.75	7.85	7.90	8.01	9.10	9.59	9.87	9.40	8.99	8.42
AESC 2011	2011$/DT	(c)	6.19	6.21	6.28	6.36	6.42	6.45	6.53	7.46	7.91	8.20	7.80	7.47	6.94
Percent Difference 2009 to 2011			-17.3%	-17.2%	-17.6%	-17.9%	-18.2%	-18.3%	-18.5%	-18.0%	-17.4%	-16.9%	-17.1%	-16.9%	-17.6%
VERMONT GAS SYSTEMS: Gas delivered via TransCanada Pipeline															
AESC 2009	2009$/DT		6.36	6.21	6.38	6.49	6.57	6.61	6.71	8.09	8.57	9.24	8.77	8.28	7.36
AESC 2009	2011$/DT		6.48	6.33	6.49	6.61	6.69	6.73	6.83	8.24	8.72	9.41	8.93	8.44	7.49
AESC 2011	2011$/DT		5.61	5.42	5.48	5.55	5.60	5.63	5.77	8.77	9.22	9.80	9.34	8.50	7.06
Percent Difference 2009 to 2011			-13.4%	-14.3%	-15.6%	-16.0%	-16.3%	-16.4%	-15.5%	6.5%	5.7%	4.2%	4.6%	0.7%	-7.2%

(a) AESC 2009 levelized costs over the 15-year period 2010 - 2024 with a discount rate of 2.218%.
(b) Factor to convert 2009$ to 2011$ 1.0186
(c) AESC 2011 levelized costs over the 15-year period 2012 - 2026 with a discount rate of 2.465%.

4.3.2. Representative New England Local Distribution Company and Resources

New England LDCs use three basic supply resources to meet the requirements of their customers. These resources are (1) gas delivered directly from producing areas via long-haul pipelines, (2) gas withdrawn from underground storage facilities (most of which are located in Pennsylvania) and delivered by pipeline, and (3) gas stored as liquefied natural gas and/or propane in tanks located in the LDC service territories throughout New England.

This avoided-cost analysis used a representative New England LDC to determine the fraction of customer requirements met from each resource each month and the fraction of storage refill in each of the summer months, April through October. The characteristics of a representative New England LDC are shown in Exhibit 4-6 below, which presents the numerical data, and Exhibit 4-4, which is a graphical representation of the typical New England LDC used in this analysis. For Vermont, which has one LDC, VGS, the characteristics of VGS were used and are shown later in this report in Section 4.5. Our analysis assumes that LDCs have optimized the mix of supply sources and thus long-term energy efficiency improvements will enable them to avoid both the fixed and the variable costs associated with their mix of supply sources.[86]

Exhibit 4-6: Representative New England LDC Monthly Characteristics of Send-out by Source, Peak-Month, and Storage Injection

AESC 2011	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual
Fractions of LDC Send-out by Source Each Month													
Pipeline Deliveries, Long-haul	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	93.9%	68.8%	57.5%	61.2%	74.9%	78.8%
Underground Storage	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%	28.2%	35.6%	34.0%	23.0%	18.5%
LNG and Propane Peaking Supply	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	3.0%	6.9%	4.8%	2.1%	2.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fraction of Annual Sendout each Month	7.9%	4.6%	3.4%	3.3%	3.3%	3.6%	5.9%	9.3%	14.4%	17.3%	15.0%	12.0%	100.0%
Monthly Sendout as a Fraction of Peak Month	45.7%	26.6%	19.7%	19.1%	19.1%	20.8%	34.1%	53.8%	83.2%	100.0%	86.7%	69.4%	
Fraction of Underground Storage Injection by Month	7.1%	17.9%	17.6%	16.2%	14.3%	14.6%	12.3%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%

Sources: Data supplied by Yankee Gas Systems, Connecticut Natural Gas Company, Columbia of Massachusetts, NSTAR and National Grid (MA).

The fractions portraying the representative New England LDC are essentially an average of the data provided by Yankee Gas Services Company, Connecticut Natural Gas Corporation, Columbia Gas of Massachusetts, NSTAR Gas Company, and National Grid (MA).

The LDC’s weighted average avoided cost in each month is a function of the avoided cost of each resource and the relative quantity of each resource used to meet the retail load each month.

4.3.3. Inputs to Avoided Costs by Resource

The cost of gas delivered to an LDC using pipeline transportation and storage facilities consists of the following four basic components:

- The unit cost of the gas commodity, which in this study is the forecast price at the Henry Hub in Louisiana;
- The demand charges for pipeline-transportation capacity, storage capacity and withdrawal capacity;
- The usage (volumetric) charges for transporting gas on a pipeline and for storage injections and withdrawals;
- The fraction (percentage) of volumes of gas received by a pipeline or storage facility that is retained by the facility for compressor fuel and losses. This fuel and loss retention increases the cost of gas above the Henry Hub price because more volumes of gas must be purchased at the Henry Hub than is delivered to the LDC. In the analysis that follows, the

[86] In a short-run marginal cost analysis only variable costs can be adjusted and thus the avoided cost is determined by the one supply source which has the highest variable cost.

fuel and loss retention is represented as the ratio of the volumes of gas purchased at the Henry Hub to the volumes of gas delivered to the LDC.

Local distribution companies generally own the LNG and/or propane tanks and accompanying liquefaction and vaporization facilities. The bulk of the New England peak gas supply comes from LNG facilities although in certain circumstances propane is the dominant peak gas source. The LDC pays for the construction, financing, operation and maintenance of the LNG facility as well as the cost of the gas that is loaded into the tank as LNG.

4.3.3.1. Commodity Costs

For this avoided-cost analysis we assume that the marginal cost of the gas commodity is the monthly price of gas at the Henry Hub. For AESC 2011, like AESC 2009, we assume that the marginal source of gas to New England LDCs from the Henry Hub is transportation and storage on either of the Tennessee Gas Pipeline (TGP), for LDCs in Northern and Central New England, or the route of Texas Eastern Transmission (TETCO) and Algonquin Gas Transmission (AGT), for LDCs in Southern New England.[87] While both the three existing LNG receiving and re-gasification terminals in New England and the terminal in New Brunswick will likely be new gas suppliers to New England, it is not likely that they will establish the avoided cost of gas supply to New England. Rather, the price of gas from these new terminals will be set by the price of gas in New England supplied by TGP and TETCO-AGT.[88]

4.3.3.2. Pipeline Rates (Charges)

As described above, we assume that the marginal source of gas to New England LDCs, other than Vermont, is transportation and storage on either of TGP or the route of TETCO and AGT. The cost for transportation and underground storage is set by the rates charged by these pipelines and their fuel and loss retention percentages, which are shown in Exhibit 4-7 and Exhibit 4-21 for Vermont Gas Systems. We assume that these rates and retention percentages will persist for the forecast period, 2011–2026; for AESC 2009 we made the same assumption.

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[87]Northern and Central New England is Massachusetts, New Hampshire and Maine; Southern New England is Connecticut and Rhode Island.

[88]Unlike in the past, the Federal Energy Regulatory Commission has decided that U.S. LNG terminals will not need to offer open access services and will be able to sell LNG at market prices. In a similar fashion the Maritimes & Northeast pipeline expansion is contracted by Repsol YPF, which is the provider of the LNG to the Canaport LNG terminal in New Brunswick. Thus this LNG will also be sold at market prices in New England.

Exhibit 4-7 shows typical rates that New England LDCs pay on the TGP and TETCO -AGP routes from the Henry Hub. These are the same rate schedules used in AESC 2007 and AESC 2009. For TGP the demand rates, in nominal dollars, and the fuel and loss retention percentages are the same as in AESC 2009.[89] The TGP usage rates are slightly higher now than in 2009. For TETCO the 2009 rates and fuel and loss retention are similar with small changes up and down. AGT's demand and usages charges are nearly identical in nominal dollars to the 2009 rates while the 2011 fuel and loss retention percentages are somewhat less.

[89] Tennessee Gas Pipeline has filed with the FERC for substantially increased rates. However, these rates are not final and it is unknown what the final rates will be. Thus, for AESC 2011 we use the known and effective rates for TGP.

Exhibit 4-7: Pipeline Rates for Transportation and Storage

AESC 2011		Demand $/DT/month	Usage $/DT	Fuel & Loss (a) Winter %	Summer %
Texas Eastern Transmission, L.P. (b)					
Transportation: FT-1, WLA - M3				Dec - Mar	Apr - Nov
WLA-AAB		2.5945			
ELA-AAB		2.1471			
M1 - M3		10.8550			
Total Demand		15.5966			
WLA - M3 usage (c)			0.0371	8.10	7.12
Storage & Transportation: SS-1					
Reservation,		5.5480			
Space (d)	($/DT/year)	0.1293		0.07	0.07
Injection			0.0267	0.97	0.97
Withdrawal (c)			0.0350	3.34	3.09
Algonquin Gas Transmission LLC (e)					
				Dec - Mar	Apr - Nov
Transportation: AFT-1 (FT-1,WS-1)		6.5734			
Usage (c)			0.0131	1.02	0.72
Tennessee Gas Pipeline Company					
				Nov - Mar	Apr - Oct
Transportation FT-A (f) (g) (c)					
Zone 1 (LA) to 6		15.15	0.1522	7.82	6.67
Zone 1 (LA) to 4		na	0.1033	5.90	5.06
Zone 4 to 6		5.89	0.0853	2.17	1.92
Storage FS - Market Area (h)					
Reservation		1.15			
Space	($/DT/month)	0.0185			
Injection			0.0102	1.49	1.49
Withdrawal			0.0102		

Sources and Notes:

(a) Fuel and loss retention percentage is applied to volumes received by the pipeline.

(b) FT-1: Part 4-Statement of Rates, Section 2 FT-1, pages 1 & 2 of 16. Effective February 1, 2011.
SS-1: Part 4-Statement of Rates, Section 9, page 1. Effective February 1, 2011
Fuel and loss: Part 4-Statement of Rates, Section 16, page 1 & 2 of 3. Effective December 1, 2010.

(c) ACA charge ($0.0019) in the Algonquin and Tennessee usage rates, but not in TETCO usage rates.
Since ACA charge levied only once in a haul, the Algonquin charge is sufficient.

(d) SS-1 space charge as listed is paid at 1/12 rate per month. Fuel and loss is collected monthly.

(e) AFT-1: Part 4-Statement of Rates, Section 1, page 1. Effective May 17, 2010.
Fuel and loss: Part 4-Statement of Rates, Section 12, page 1. Effective December 1, 2010.

(f) FT-A: Tariff Sheet Nos. 14 effective July 1, 2010 and Sheet No. 15 effective April 19, 2010.
Even if the receipt point is in Zone L the rate is from Zone 1 to delivery zone. L rate is only for receipt and delivery in Zone L.

(g) Tennessee transportation fuel & loss retention percentages on Sheet No. 32 effective April 19, 2010

(h) FS: Sheet No. 61 effective July 1, 2010.

4.3.3.3. Long-Haul Pipeline "Cash" Costs

Gas is delivered to the LDC each month by pipelines from producing areas, in this analysis assumed to be the Henry Hub.[90] "Cash cost" means the avoided cost of transportation arising from pipeline usage charges, which are paid for each dekatherm of gas transported, and the demand charges allocated to that month, which pay for the reservation of pipeline capacity whether used or not. The avoided commodity cost of gas purchased was the price of gas at the Henry Hub that month multiplied by the ratio of the Henry Hub volume purchased to one dekatherm of gas delivered to the LDC. Because of the retention of gas for fuel and loss in both transportation and storage, more than one dekatherm of gas must be purchased at the Henry Hub in order to deliver one dekatherm to the LDC.

This ratio of gas volumes purchased at the Henry Hub to one dekatherm of gas delivered to the LDC was established by the fuel and loss retention percentages of the various pipeline transportation and storage services used between the Henry Hub and the LDC. For example, assume that the gas is transported by two pipelines: A and B from the Henry Hub to the LDC. The fuel and loss percentage is 6 percent for A (Fa) and 4 percent for pipeline B (Fb). The fuel and loss amount taken by the pipeline is based on the volumes received by the pipeline (R) while the demand and usage charges are based on the volume of gas delivered by the pipeline (D). In order to compute the ratio of gas received to that delivered the following equations were used:

1. $D = R - FR$
2. $D = R(1-F)$
3. $R/D = 1/(1-F)$

For pipeline A; $Ra/Da = 1/(1-.06) = 1.0638$; or $Ra = 1.0638\ Da$

For pipeline B; $Rb/Db = 1/(1-.04) = 1.0417$; or $Rb = 1.0417\ Db$

Since Db is the amount delivered to the LDC, Ra/Db or the ratio of the amount to be purchased in the field to the amount delivered to the LDC is what needs to be computed.

Since: $Rb = Da$

$Ra = 1.0638\ Da = (1.0638)Rb = (1.0638)(1.0417)Db$

Thus: $Ra/Db = (1.0638)(1.0417) = 1.1082$

[90] Rate schedules assumed for the long-haul transportation: TETCO, FT-1 from zone WLA to zone M3; AGT, AFT-1 (FT-1) and TGP, FT-A from Zone 1 to Zone 6.

Or: 1.1082 DT of natural gas must be purchased for each DT delivered.

4.3.4. Avoided Costs of Supply (Energy) by Resource by Month

The LDC's weighted average avoided cost in each month is a function of the avoided cost of each resource and the relative quantity of *sendout* provided by each source each month. Exhibit 4-8 provides illustrative avoided costs by gas source and pipeline route for gas delivered to New England LDCs in January and June. The relative quantities of sendout, and injections into storage, by month by resource for a typical New England LDC are shown in Exhibit 4-6. Our estimates of the avoided cost of each resource by month are described below.

Exhibit 4-8: Comparison of Avoided Costs of Delivering One Dekatherm of Gas to a New England LDC from Three Sources of Natural Gas and Peak Day

		Texas Eastern & Algonquin		Tennessee Gas Pipeline	
		January	June	January	June
	units				
Pipeline Long-haul to LDC					
Total Demand Cost of Gas Delivered to LDC	2011 $/DT	$1.13	$0.00	$0.77	$0.00
Total Usage Cash Cost of Gas delivered to LDC	2011 $/DT	$0.05	$0.05	$0.15	$0.15
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.099	1.084	1.085	1.071
Delivered From Underground Storage					
Total Demand Cost of Gas Delivered to LDC from UG Storage	2011 $/DT	$1.43		$1.21	
Total Cash cost for refill + Usage Cost of Gas delivered to LD(	2011 $/DT	$0.79		$0.96	
Ratio of Gas Purchased to Gas Delivered to LDC		1.136		1.093	
LNG Regasified into LDC System					
Total Demand Cost of Gas Delivered to LDC for LNG refill	2011 $/DT	$0.91		$0.62	
Total Usage Cash Cost of Gas delivered to LDC for LNG refill	2011 $/DT	$0.06		$0.19	
Ratio of Gas Purchased at HH to Regasified Gas at the LDC		1.347		1.331	
Peak Day in January From Underground Storage					
Pipeline Cash Demand Cost of Gas Delivered to LDC	2011 $/DT	$100.13		$84.79	
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2011 $/DT	$0.79		$0.96	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.136		1.093	
Basaed on pipeline rates effective on 25 April 2011.					

4.3.4.1. Direct Long-Haul Pipeline Delivery

The analysis of a typical New England LDC send-out and storage refill shown in Exhibit 4-6 indicates that LDCs use 100 percent of their pipeline capacity to provide deliver supply in winter months. The use of the long-haul transportation capacity in the winter varies from about 90 percent in November and March to 100 percent in January. In summer months they use approximately 75 percent of this capacity. AESC 2011 allocates the winter-month pipeline-transportation-demand charges plus 25 percent of summer demand charges among the five winter months according to the quantity of capacity used each winter month. As a result, the avoided transportation demand cost varies among the five winter months with the month of heaviest use, January, receiving the largest allocation of demand charges.

Of that 75% of pipeline capacity LDCs use in the summer, they use 29% to deliver gas for injection into storage and 46 percent to provide direct supply.

- We allocate the costs of demand and usage charges and the fuel and loss fraction for pipeline transportation from the Henry Hub to refill storage to the avoided cost of underground storage and LNG peaking services.[91]
- We assume that an LDC will not avoid any capacity cost due to a reduction in summer load, because it needs to hold the capacity entitlement in order to serve its winter load and because the market value of short-term, summer releases of pipeline capacity is close to zero. This low market value is reflected in the low basis differentials in the summer between the Henry Hub and either the ALG gas spot market or the TGP Z6 spot gas market. The basis differential for each market is enough to cover the usage charges and fuel, but there is little or no amount remaining to pay for demand charges. This means that an LDC would continue to pay the full demand charge in each summer month even if the gas requirements of customers were reduced due to energy efficiency in the summer; thus the LDC would not avoid the summer pipeline demand charges.

4.3.4.2. Underground Storage

Natural gas is delivered to the LDC from underground storage during the five winter months of November through March; see Exhibit 4-4. For both TETCO and TGP, the underground storage is located in Pennsylvania. The avoided cost of underground storage supply for one dekatherm in January is shown in Exhibit 4-8.

The avoided cost of underground storage included the cost of buying gas at the Henry Hub, pipeline demand and usage charges to bring gas to the storage facility in the summer, the cost of injection, the demand cost of storage capacity, the demand and variable costs of withdrawing gas from storage and the demand and variable costs of transporting gas to the LDC from underground storage.[92]

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[91] This follows the same methodology used in AESC 2009.

[92] Rate schedules used in the calculation for the TETCO-AGT route are: TETCO, FT-1 zone WLA to zone M3; storage on TETCO and transportation to AGT, SS-1; and transportation to the LDC on AGT, AFT-1 (WS-1). Rate schedules used in the Tennessee route are: TGP, FT-A zone 1 to zone 4; storage on TGP, FS–market area; and transportation to the LDC on TGP, FT-A zone 4 to zone 6.

The cost of gas injected into storage was the cost of buying gas at the Henry Hub, as adjusted for fuel and loss retention, plus the cost of transportation to underground storage including both demand and usage costs at 100 percent load factor. The cost of the gas injected into storage was less than the average cost of gas for a year, 96.9 percent of the annual cost, because gas is purchased for injection during the summer months when the price of gas is less than average.

Pipelines bill demand charges to LDCs for the capacity that LDCs hold for withdrawal of gas from storage and transportation to their system every month of the year. Because gas is withdrawn from underground storage and delivered to an LDC only during the 5 winter months, we allocated a full year of withdrawal and transportation-demand charges to the five winter months.[93] These annual demand charges were allocated among each of the five winter months according to the relative quantity of capacity the LDC used in each month to transport gas from underground storage to its city gate. January is the peak send-out month from all gas sources and from underground storage; the other winter months, especially November and March, experience less send-out as shown in Exhibit 4-6. Thus, the demand cost of unused capacity of storage withdrawal and of transportation capacity from underground storage to the LDC in November and March was assigned to the sendout during December through February based on usage each month. Similarly, the unused capacity during December and February was assigned to the cost of withdrawing and transporting gas to the LDC in January.

4.3.4.3. Liquid Natural Gas and Peak Shaving

There are 46 liquefied-natural-gas (LNG) tanks in New England in addition to the Distrigas LNG import terminal. These tanks, and to a lesser extent propane, provide peak-shaving supply for LDCs. The costs avoided by peak shaving are based only on LNG in AESC 2011. These facilities have fixed and variable costs. The estimate of avoided costs was based on the variable costs only.

The major embedded or accounting costs of LNG send-out for peaking service are the fixed costs of building the tank, vaporization and liquefaction capacity, and the fixed costs of operation and maintenance. However, these fixed costs are likely to be unaffected by reductions in gas demand due to modest-sized efficiency improvement measures. These fixed costs are sunk costs. Moreover, LNG peaking facilities have strong economies of scale and thus are lumpy investments. They are

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[93] This is true of the storage and delivery service of TETCO in rate schedule SS-1 as well at withdrawal from storage and transportation to the LDC on TGP. However, AGT has a winter service, WS, firm transportation from the interconnection with TETCO to New England LDCs which has demand charges for only the five winter months. AESC 2007 reflects AGT's five months of demand charges in its allocation and calculation.

likely to be sized to accommodate growth in gas send-out. In addition, the cost of changing the capacity of send-out is the cost of vaporization facilities, which is a small portion of the total fixed costs of the LNG peaking facility. Thus, it was assumed that the avoided cost of LNG peaking facilities due to efficiency improvements should ignore these fixed costs.

The avoided costs of LNG peaking are the variable costs of the LNG; the cost of gas at the Henry Hub, costs of pipeline transport to bring gas to the LNG facility, including pipeline demand charges, and then the variable costs of liquefaction and re-gasification.[94] The variable costs of liquefaction and vaporization are principally the gas that is used in the liquefaction stage and the vaporization stage. It was assumed that fuel use is 17 percent for liquefaction and 3% for vaporization. This is the same cost methodology used in AESC 2009.

The estimated avoided cost of LNG peaking service varies by time and pipeline; see Exhibit 4-8.

4.3.5. Avoided Costs of Peak Day Supply

The Scope of Work requests estimates of the future natural gas costs avoided by energy efficiency programs provided as all in values in $/MMBtu as well as provided as separate values for avoided energy ($/MMBtu) and avoided peak-day capacity ($/MMBtu). This section describes the calculation of an estimate of avoided peak-day capacity costs.

First, it is not clear that program administrators need an estimate of peak-day capacity costs to estimate the benefits of gas efficiency programs. Unlike electricity programs that reduce demand only during peak hours, there do not appear to be any efficiency programs that reduce gas use only on a peak day. Further, the “capacity value” of gas efficiency programs that reduce gas use over an entire year or over a heating season is incorporated in our projection of all in values of gas avoided costs in $/MMBtu. Our estimate of avoided gas cost at the city gate by month includes both avoided fixed costs (cash pipeline demand charges) and variable costs (gas commodity costs, cash pipeline usage charges and adjustments for fuel and losses in pipeline transportation and storage of gas). These avoided costs, plus avoided distribution costs, provide the full avoided cost of gas by end uses that LDCs need to evaluate gas efficiency programs. The

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[94] Rate schedules used for the long-haul transportation of gas in the summer to be liquefied are the same as those cited for long-haul transportation: TETCO, FT-1 from zones WLA to zone M3; AGT, AFT-1 (FT-1) and TGP, FT-A from zone 1 to zone 6. LDC LNG tanks are also filled by hauling imported LNG from the Distrigas facility to the LNG tank by tanker truck. However, we assume that Distrigas will price this LNG at the LDC’s avoided cost of liquefaction.

avoided costs presented in Exhibit 4-5 are comprehensive and provide the full value of reductions in gas use in New England.

Second, there are differences between the gas industry and the electric industry that affect the calculation of avoided electric capacity costs versus avoided gas peak-day costs. In electricity distribution, load-serving entities (LSEs) responsible for providing firm supply of electricity to retail customers acquire a sufficient total quantity of capacity to ensure reliable service using a mix of different types of resources. The New England electric industry has separate, explicit wholesale markets for electric capacity and for electric energy. ISO-NE requires load-serving entities to hold sufficient total capacity equal to their projected summer coincident peak plus an additional reserve equal to an explicit "reserve margin multiplier." The electric reserve margin multiplier reflects the additional quantity of capacity in order to ensure reliability. It is in the range of 15 percent: LSEs are required by ISO-NE to hold capacity equal to 1.15 times their projected peak demand under normal conditions. This is a uniformly applied regulatory requirement that allows a calculation of avoided cost when the peak requirement is reduced by efficiency programs: usually assuming a gas-fired combustion turbine is the proxy for the cost of the peaking resource.

But the electricity and gas industries are different. Gas can be and is stored in substantial quantities in various ways: LNG tanks, underground storage, and line pack. In contrast, electricity, as a practical matter, cannot be stored. Furthermore, the flow of electricity in the electricity grid is controlled largely by Kirchoff's laws, which at times of stress has led to large scale blackouts. In contrast, the flow of gas in the gas grid is controlled by compressors and valves that are themselves controlled by people who follow contracts, nominations, and, occasionally, emergency protocols. These differences have led to some of the differences in regulation and operation between the gas and electricity industry.

Unlike the electricity industry, the New England gas industry LDCs buy gas largely in the wholesale markets of production areas of the U.S. Southwest, Appalachia, and Canada, and some perhaps in the New England wholesale market for gas energy. Rather LDCs buy transmission and underground storage capacity from pipelines via bilateral contracts where the prices are generally set in a FERC regulated tariff. Moreover there is no equivalent to ISO-NE that imposes explicit uniform reliability requirements to LDCs in New England. Instead, it is our understanding that each LDC determines the total physical quantity of capacity it needs to hold to ensure reliable supply service under two sets of design conditions. The first set is a *design day*, a needle peak demand during 1day of substantially colder-than-normal temperatures that occur only rarely. The second set is a *design winter,* the level of sendout in each month of a winter with colder-than-normal temperatures. LDCs must demonstrate to their state regulators that they hold sufficient capacity to ensure reliable service.

Local distribution companies acquire the capacity needed to meet design-day demands from a range of resources, according to their particular location and circumstances. For example Vermont Gas Systems relies on spot gas for peaking for normal winters under an arrangement with its supply pipeline with backup propane-air for exceptionally cold days. Many New England LDCs use local LNG storage facilities to meet peak day requirements. One New York utility appears to rely upon a large, gas-fired cogeneration power plant to switch to No. 2 fuel oil and release gas to the LDC on a few peak days in a year. Thus, there is not a common resource used to meet peak-day requirements.

However, we provide an estimate of avoided peak-day costs for those LDCs who do choose to include an avoided peak-day cost. Other LDCs may choose to adjust this estimate upward to account for their design-winter reserve margin, e.g. perhaps 10% greater than during a normal winter sendout, when computing their avoided cost. The avoided demand charges for each month of the winter will provide the number for such an addition to the avoided costs computed here.

4.3.5.1. Peak-Day Avoided Cost

Liquid-natural-gas peaking facilities are generally used to meet the peak-day requirements of New England LDCs. The fixed costs were excluded from the estimate of the avoided costs for the LNG facilities. The resulting modest cost, which excludes fixed costs, does not properly capture the high avoided costs that are expected for peak day service.

Consequently, peak-day avoided costs are estimated based on the costs of underground storage. We assume that underground storage and transportation capacity to the LDC was needed to meet a one-day peak even though the demand charges are generally paid for twelve months.[95] Thus, in calculating the peak-day avoided cost, the demand charges for all twelve months were allocated to the one-day peak.

The estimate of peak-day avoided costs is shown in Exhibit 4-8 for both the TETCO-ALG and the TGP routes. As can be seen, greater incremental demand charges, especially when several pipelines are used for transportation, produce high peak-day avoided costs.

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[95] In the case of transportation of stored gas to New England on AGT, a winter service is used for which demand charges are paid for only the five-month winter period.

An alternative estimate of the avoided cost of natural gas on a peak-day to a New England LDC is the spot market price of natural gas in New England on a peak day. The largest peak-day sendout in New England since 2002 occurred on January 15, 2004 (Leahey 2008, 62). During that day the spot price of gas in ALG was $63.42 per dekatherm, and the spot price at TGP Zone 6 was $49.81 per dekatherm.

4.3.6. Total Avoided Costs by Month

The avoided costs of natural gas were determined by month in two of the three geographic areas: Northern and Central New England (Massachusetts, New Hampshire and Maine) and Southern New England (Connecticut and Rhode Island). The avoided cost forecast for Vermont is presented later within this chapter. The avoided cost of natural gas by month is calculated as the weighted average of the avoided cost of gas delivered to the LDC from each of the three sources: long-haul pipeline, underground storage, and LNG storage.

The weightings each month are shown in Exhibit 4-6 above under the "Fraction of Annual Sendout Each Month" section of the exhibit.[96]

Like AESC 2009, we assume that the avoided cost in Southern New England is the cost of gas delivered to LDCs by the Texas Eastern and Algonquin pipeline route. Similarly, we assume that the avoided cost of gas delivered to LDCs in Northern and Central New England was provided by Tennessee Gas Pipeline.

The avoided cost forecast by month for Southern New England, Northern and Central New England, and Vermont Gas Systems are detailed in Appendix D. Also shown in the appendix is the annual Henry Hub forecast price of natural gas. Other than for the estimated peak-day avoided cost, the commodity cost of gas based on the Henry Hub price was the largest component of the avoided cost.

The levelized avoided cost is the cost for which the present value at the real rate of return of 2.465 percent has the same present value as the estimated avoided costs for the years 2012 through 2026 at the same rate of return.

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[96]The summer periods, April–October, and November and December all fall within a single calendar year; thus, the commodity cost of gas for those months is based on the Henry Hub price for that calendar year. However, the winter periods, November–March, span calendar years. The majority of gas delivered in the winter is from LNG and underground storage, which was purchased during the previous summer. Thus, we assume that the commodity cost of gas from underground storage and LNG is based on the Henry Hub price from the year in which the winter delivery period begins. However, we assume that the gas supplied directly from the long-haul pipeline delivery is purchased in the month of delivery and thus January–March costs are based on the Henry Hub price for the following year.

4.3.6.1. Comparison with the AESC 2009 Avoided-Cost at an LDC City Gate

Avoided costs at the LDC city gate, excluding the cost of purchased gas, by source in AESC 2011 are very similar to those in AESC 2009, see Exhibit 4-9.[97] Rates did not change much from 2009 to 2011 in nominal terms. When comparing these costs by source in 2011 dollars the AESC 2009 costs are higher because the rates charged by TETCO, AGT, and TGP do not keep up with inflation. The major difference in the avoided costs will be due to changes in the cost of gas at Henry Hub.

Exhibit 4-9: Illustrative Comparison of AESC 2007 and AESC 2009 Avoided Costs by Source: TETCO-AGT to Southern New England

	units	AESC 2009	AESC 2009	AESC 2011
		2009$/DT	2011 $ per Dekatherm	
Pipeline Long-haul to LDC				
Total Demand Cost of Gas Delivered to LDC	$/DT	$0.99	$1.01	$1.13
Total Usage Cash Cost of Gas delivered to LDC	$/DT	$0.07	$0.08	$0.05
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.099	1.099	1.099
Delivered From Underground Storage				
Total Demand Cost of Gas Delivered to LDC from UG Storage	$/DT	$1.37	$1.40	$1.43
Total Cash cost for refill + Usage Cost of Gas delivered to LDC	$/DT	$0.83	$0.85	$0.79
Ratio of Gas Purchased to Gas Delivered to LDC		1.145	1.145	1.136
LNG Regasified into LDC System				
Total Demand Cost of Gas Delivered to LDC for LNG refill	$/DT	$0.91	$0.93	$0.91
Total Usage Cash Cost of Gas delivered to LDC for LNG refill	$/DT	$0.09	$0.09	$0.06
Ratio of Gas Purchased at HH to Regasified Gas at the LDC		1.349	1.349	1.347
Peak Day in January From Underground Storage				
Typical Rates				
Pipeline Cash Demand Cost of Gas Delivered to LDC	$/DT	$100.33	$102.20	$100.13
Pipeline Cash Commodity Cost of Gas Delivered to LDC	$/DT	$0.83	$0.85	$0.79
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.145	1.145	1.136
AESC 2009 based on pipeline rates effective May 12, 2009. AESC 2011 based on rates effective April 25, 2011				
`Convert 2009 $ to 2011 $	1.0186			

The changes in the demand charges for the long haul pipeline are due to differences in the allocation of demand charges between the two studies. The reduced fuel and loss for storage in AESC 2011 reflects the lowered AGT fuel and loss retention in AESC 2011 compared with AESC 2009.

97 This comparison is for the pipeline route of TETCO and AGT. However, the comparison of avoided-cost estimates along the TGP route would provide similar qualitative comparisons.

4.4. Avoided Gas Costs by End Use

End uses of natural gas at retail are distinguished by the type of end-use: heating or low load factor, non-heating or high load factor and all. The costs associated with these end-uses also vary by the type of customer or sector, i.e., residential, commercial, and industrial.[98]

4.4.1. Load Shape by End Use

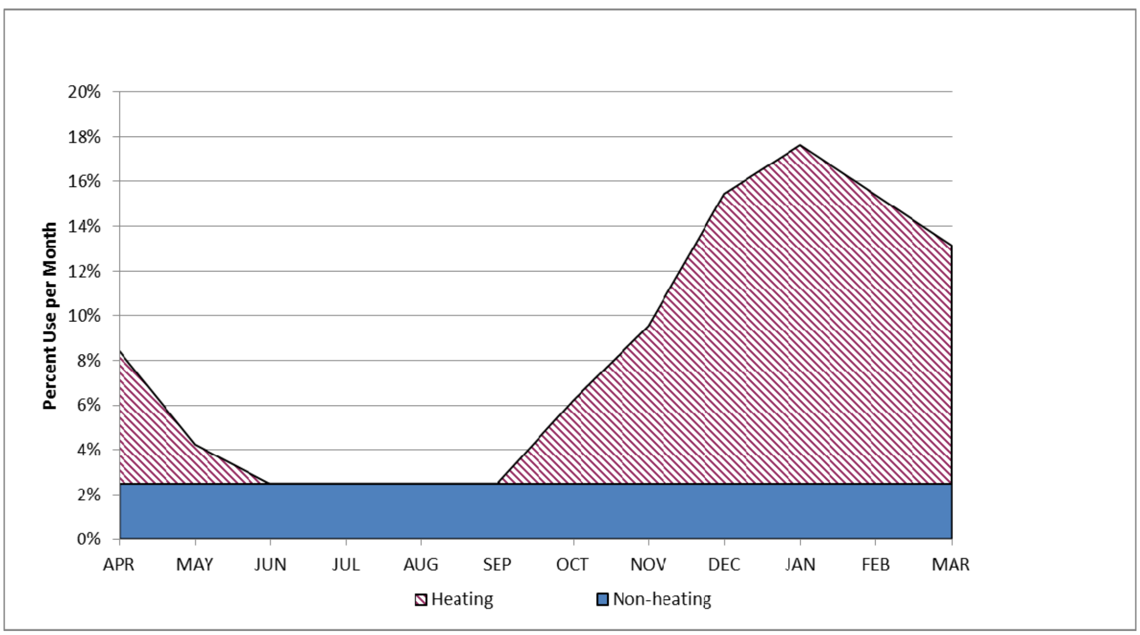
The different types of end-use have different profiles of gas use by month as shown in Exhibit 4-10 and Exhibit 4-11. Exhibit 4-10 shows the load profile of heating loads as percentages, which are graphed in Exhibit 4-11.

Exhibit 4-10: End-Use Load Profiles

		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	ANNUAL
Non-Heating (high load factor)	(a)	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.34%	8.34%	8.34%	8.34%	8.33%	100.00%
	30%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	
Heating Load (low load factor)	(b)	8.50%	2.50%	0.00%	0.00%	0.00%	0.00%	5.30%	10.00%	18.50%	21.60%	18.40%	15.20%	100.00%
	70%	5.95%	1.75%	0.00%	0.00%	0.00%	0.00%	3.71%	7.00%	12.95%	15.12%	12.88%	10.64%	
All Loads: Heating and Non-heating	(c)	8.45%	4.25%	2.50%	2.50%	2.50%	2.50%	6.21%	9.50%	15.45%	17.62%	15.38%	13.14%	100.00%

(a) Constant load all year; rounding altered in the winter months to maintain 100% use for the year.
(b) Distribution of the heating (low load factor) load among the months of the year based on data provided by National Grid (MA).
(c) Weighted average for each month at 70% heating load shape and 30% non-heating load shape. Distribution between heating load and non-heating load based on data from National Grid (MA).

Exhibit 4-11: End-Use Load Profiles Graphed



[98]The electric power sector is not addressed here.

The heating loads occur October through May with a peak in January. This load profile is derived from data provided by National Grid (MA) with some slight modification using New England heating degree-day data. The non-heating load is constant year round while all loads are represented as the weighted average between the heating and the non-heating load weighted 70 percent to heating and 30 percent to non-heating.

4.4.2. Avoided Distribution Cost by Sector

The avoided cost for each end use by sector and the retail sector is the sum of the avoided cost of the gas sent out by the LDC and the avoidable distribution cost, called the avoidable LDC margin, applicable from the city gate to the burner tip.

Estimates of the portion or amount of distribution cost that is avoidable due to reductions in gas use from efficiency measures vary by LDC. Some LDCs have estimated this amount as their incremental or marginal cost of distribution; that is, the change in cost of distribution incurred as demand for gas increases or decreases. The conclusion was that the incremental cost of distribution depends upon the load type and the customer sector. For low load factor or heating loads more of the embedded cost for each sector is incremental or avoidable than for high load factor or non-heating loads. The incremental or avoidable cost is measured as a percent of the embedded costs. For AESC 2011, we measure the embedded cost as the difference between the city-gate price of gas in a state and the price charged each of the different retail customer types: residential, commercial - industrial, and all retail customers.[99] The embedded distribution cost for each of the two regions, Southern and Northern and Central, were the weighted average distribution costs among the relevant states where the weighting is the volumes of gas delivered to each sector in each state.

Exhibit 4-12 shows the estimated avoidable LDC margin percentage and avoidable costs, measured as 2011 dollars per dekatherm, by each of the end-use types and customer sectors for each region in New England.

[99]The city-gate gas prices and the prices charged to each retail customer sector are reported by the Energy Information Administration for each state each year. In AESC 2011 the cost used are the average for the 5 years 2005-2009, which is the most recent data available.

Exhibit 4-12: Avoidable LDC Margin

Estimated Avoidable LDC Margins (a) (2011$/dekatherm)				
	Total LDC Retail Margin & CG Price	Avoidable LDC Margin		
Type of End Use		Non-heating (High Load Factor)	Heating (Low Load Factor)	All
Avoidable Margin (percent) (b)				
Residential		8.0%	21.0%	20.4%
Commercial & Industrial		15.0%	28.0%	24.0%
All Retail				22.0%
Southern New England (c)				
Average City Gate Price	9.550			
Residential	7.527	0.60	1.58	1.54
Commercial & Industrial (e)	3.615	0.54	1.01	0.87
All Retail (f)	5.348			1.18
Northern & Central New England (d)				
Average City Gate Price	10.153			
Residential	6.576	0.53	1.38	1.34
Commercial & Industrial (e)	4.334	0.65	1.21	1.04
All Retail (f)	5.408			1.19
Vermont				
Average City Gate Price	9.312			
Residential	5.962	0.48	1.25	1.22
Commercial & Industrial (e)	1.597	0.24	0.45	0.38
All Retail (f)	3.189			0.70

Source: EIA website data sources.
(a) Average of Margins among states for 2005 - 2009 weighted by the delivered volumes in each state.
(b) Based on LDC marginal cost studies from National Grid (MA).
(c) Southern New England is Rhode Island and Connecticut
(d) Northern & Central New England is Massachusetts, New Hamshire and Maine.
(e) An average of the margins weighted by the commercial and industrial use delivered volumes.
(f) An average of residential, commercial and industrial margins weighted by associated volumes.

Other LDCs assume they will not avoid any distribution costs due to reductions in gas use from efficiency measures. The avoided cost of gas by end-use for an LDC with no avoided distribution cost is their avoided cost of gas delivered to their city-gate.

4.4.3. Avoided Costs by End-Use

Exhibits 4-13 through 4-16 and Appendix D for Vermont Gas Systems show the total avoided costs per year per Dekatherm for the retail end-uses categorized by the end-use type and customer sector for Southern New England and Northern and Central New England. The avoided cost of the gas sent out by the LDCs by load type is the weighted sum across all months of the avoided cost per dekatherm each month delivered to the city gate as detailed in Appendix D, multiplied by the percent used each month for each load type (heating, non-heating or all) plus the avoided retail margin for each retail customer sector. The levelized avoided cost is the cost for which the present value at the real rate of return of 2.465 percent has the same present value as the estimated avoided costs for the 15-year period 2012 through 2026 at the same rate of return. The resulting avoided cost each year for the different load types is shown in Appendix D.

Exhibit 4-1, which summarizes Exhibit 4-13 and Exhibit 4-14, shows the total levelized avoided costs if some retail margin is avoidable. Exhibit 4-2, which summarizes Exhibit 4-15 and Exhibit 4-16, shows the total levelized avoided costs if no retail margin is avoidable. Exhibit 4-13 and Exhibit 4-14 provide projections of avoidable cost by end-use for utilities in Southern New England and Northern and Central New England for which some LDC retail margin is avoidable.

Exhibit 4-13: Avoided Cost of Gas Delivered to an End Use Load, Assuming Some Retail Margin is Avoidable; Southern New England

AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
SOUTHERN NEW ENGLAND BY END USE
ASSUMING SOME AVOIDABLE RETAIL MARGIN
Gas Delivered via Texas Eastern and Algonquin Gas Pipelines
(2011$/Dekatherm)

Year	RESIDENTIAL Non Heating	RESIDENTIAL Hot Water annual	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2011	5.97	5.97	7.74	7.46	5.91	7.17	6.79	7.10
2012	6.49	6.49	8.21	7.94	6.43	7.64	7.27	7.58
2013	6.70	6.70	8.42	8.15	6.64	7.86	7.49	7.80
2014	6.98	6.98	8.81	8.51	6.92	8.24	7.84	8.15
2015	7.56	7.56	9.28	9.01	7.50	8.71	8.34	8.65
2016	7.59	7.59	9.30	9.04	7.53	8.74	8.37	8.68
2017	7.57	7.57	9.29	9.02	7.51	8.72	8.35	8.66
2018	7.59	7.59	9.32	9.05	7.53	8.75	8.38	8.69
2019	7.64	7.64	9.37	9.10	7.58	8.80	8.43	8.74
2020	7.73	7.73	9.47	9.20	7.67	8.90	8.53	8.84
2021	7.83	7.83	9.58	9.30	7.77	9.01	8.63	8.94
2022	7.96	7.96	9.75	9.46	7.90	9.18	8.80	9.10
2023	8.25	8.25	10.03	9.74	8.19	9.46	9.07	9.38
2024	8.44	8.44	10.20	9.92	8.38	9.63	9.25	9.56
2025	8.51	8.51	10.29	10.00	8.45	9.72	9.33	9.64
2026	8.64	8.64	10.42	10.14	8.58	9.85	9.47	9.78
Levelized (a)	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
Simple Average	7.70	7.70	9.45	9.17	7.64	8.88	8.50	8.81

(a) Years 2012-2026 (15 years); Real (constant $) riskless annual rate of return in %: 2.465%

Exhibit 4-14: Avoided Cost of Gas Delivered to an End Use Load, Assuming some Retail Margin is Avoidable; Northern & Central New England

AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
NORTHERN & CENTRAL NEW ENGLAND BY END USE
ASSUMING SOME AVOIDABLE RETAIL MARGIN
Gas Delivered via Tennassee Gas Pipeline
(2011$/Dekatherm)

Year	RESIDENTIAL Non Heating	RESIDENTIAL Hot Water annual	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating annual	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2011	5.82	5.82	7.35	7.11	5.95	7.18	6.80	6.95
2012	6.34	6.34	7.80	7.58	6.46	7.64	7.28	7.43
2013	6.54	6.54	8.01	7.79	6.67	7.85	7.49	7.64
2014	6.82	6.82	8.39	8.14	6.95	8.23	7.84	7.99
2015	7.39	7.39	8.86	8.63	7.51	8.69	8.33	8.48
2016	7.42	7.42	8.88	8.66	7.55	8.71	8.36	8.51
2017	7.40	7.40	8.87	8.64	7.52	8.70	8.34	8.49
2018	7.42	7.42	8.89	8.67	7.55	8.73	8.37	8.52
2019	7.47	7.47	8.95	8.72	7.59	8.78	8.42	8.57
2020	7.56	7.56	9.04	8.82	7.68	8.88	8.51	8.66
2021	7.66	7.66	9.15	8.92	7.78	8.98	8.62	8.77
2022	7.79	7.79	9.32	9.08	7.91	9.15	8.78	8.93
2023	8.07	8.07	9.59	9.35	8.19	9.42	9.05	9.20
2024	8.26	8.26	9.76	9.53	8.38	9.59	9.22	9.37
2025	8.33	8.33	9.84	9.61	8.46	9.68	9.31	9.46
2026	8.45	8.45	9.98	9.74	8.58	9.81	9.44	9.59
Levelized (a)	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
Simple Average	7.53	7.53	9.02	8.79	7.65	8.86	8.49	8.64

(a) Years 2012-2026 (15 years); Real (constant $) riskless annual rate of return in 2.465%

Exhibit 4-15 and Exhibit 4-16 show the avoided cost by end-use for utilities at which it is assumed that no LDC retail margin is avoidable.

Exhibit 4-15: Avoided Cost of Gas by End Use Load Type, Southern New England

AVOIDED COSTS OF GAS DELIVERED TO LDCs BY END-USE LOAD TYPE: ASSUMING NO AVOIDABLE RETAIL MARGIN Southern New England Gas Delivered via Texas Eastern and Algonquin Pipelines (2011$/Dekatherm)					
	END-USE LOAD TYPE				Annual
Year	Heating	Non-Heating	All	Annual Average	Henry Hub Price
2011	6.16	5.37	5.92	5.37	4.37
2012	6.63	5.89	6.41	5.89	4.91
2013	6.84	6.10	6.62	6.10	5.10
2014	7.23	6.38	6.97	6.38	5.29
2015	7.70	6.95	7.48	6.95	5.91
2016	7.72	6.99	7.50	6.99	5.96
2017	7.71	6.97	7.49	6.97	5.93
2018	7.74	6.99	7.51	6.99	5.95
2019	7.79	7.03	7.56	7.03	5.98
2020	7.89	7.13	7.66	7.13	6.06
2021	7.99	7.23	7.77	7.23	6.16
2022	8.17	7.36	7.93	7.36	6.25
2023	8.45	7.64	8.21	7.64	6.52
2024	8.62	7.84	8.38	7.84	6.72
2025	8.70	7.91	8.47	7.91	6.78
2026	8.84	8.04	8.60	8.04	6.89
Levelized (a)	7.81	7.04	7.57	7.04	5.97
Simple Average	7.87	7.10	7.64	7.10	6.03
(a)	15 Years (2012 - 2026) at the Real (constant $) Discoi			2.465%	

Exhibit 4-16: Avoided Cost of Gas by End Use Load Type, Northern and Central New England

AVOIDED COSTS OF GAS DELIVERED TO LDCs BY END-USE LOAD TYPE: ASSUMING NO AVOIDABLE RETAIL MARGIN Northern & Central New England Gas Delivered via Tennesse Gas Pipeline (2011$/Dekatherm)					
	END-USE LOAD TYPE				Annual
Year	Heating	Non-Heating	All	Annual Average	Henry Hub Price
2011	5.96	5.30	5.76	5.30	4.37
2012	6.42	5.81	6.24	5.81	4.91
2013	6.63	6.02	6.45	6.02	5.10
2014	7.01	6.30	6.80	6.30	5.29
2015	7.48	6.86	7.29	6.86	5.91
2016	7.50	6.90	7.32	6.90	5.96
2017	7.48	6.87	7.30	6.87	5.93
2018	7.51	6.90	7.33	6.90	5.95
2019	7.57	6.94	7.38	6.94	5.98
2020	7.66	7.03	7.47	7.03	6.06
2021	7.77	7.13	7.58	7.13	6.16
2022	7.94	7.26	7.74	7.26	6.25
2023	8.21	7.54	8.01	7.54	6.52
2024	8.38	7.73	8.18	7.73	6.72
2025	8.46	7.81	8.27	7.81	6.78
2026	8.60	7.93	8.40	7.93	6.89
Levelized (a)	7.58	6.94	7.39	6.94	5.97
Simple Average	7.64	7.00	7.45	7.00	6.03
(a)	15 Years (2012 - 2026) at the Real (constant $) Discor			2.465%	

4.4.4. Comparison of Avoided Retail Gas Costs with AESC 2009

Exhibit 4-17, shows that the end use avoided costs of gas use in AESC 2011 are less than estimated in AESC 2009 for all states in New England assuming that some retail margin is avoidable.[100] There are two major reasons for this: 1) we now forecast lower gas prices at the Henry Hub than in AESC 2009 and 2) the estimates of avoided retail margin are less than in AESC 2009.

[100] Exhibit 4-17 is the same as Exhibit 4-1 and Exhibit 4-18 is the same as Exhibit 4-2.

Exhibit 4-18 shows the end use avoided costs of gas use if one assumes that no retail margin is avoidable in AESC 2011 but that the avoidable retail margin estimated in AESC 2009 remains.

Exhibit 4-17: Comparison of Avoided Cost with Those of AESC 2009 Assuming Some Retail Margin Avoided

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2009 AND AESC 2011
ASSUMING SOME AVOIDABLE RETAIL MARGIN
(2011$/Dekatherm except where indicated as 2009$/DT

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
2009 to 20119 change	-34.33%	-34.33%	-36.54%	-33.82%	-24.71%	-26.84%	-26.08%	-29.92%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
2009 to 2011 change	-32.57%	-32.57%	-35.03%	-32.38%	-25.64%	-28.37%	-27.41%	-29.99%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
2009 to 2011 change	-23.86%	-23.86%	-21.95%	-20.36%	-10.57%	-5.67%	-6.82%	-12.44%

(a) Factor to convert 2009$ to 2011 $ 1.0186
Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discoiunt rate of 2.465%.

Exhibit 4-18: Comparison of Avoided Cost with Those of AESC 2009 Assuming No Retail Margin is Avoided in AESC 2011

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS BY END USE: AESC 2009 AND AESC 2011 NO AVOIDABLE RETAIL MARGIN in AESC 2011 but is in AESC 2009 (2011$/Dekatherm except where indicated as 2009$/DT								
	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.04	7.04	7.81	7.57	7.04	7.81	7.57	7.57
2009 to 20119 change	-39.50%	-39.50%	-47.23%	-44.98%	-30.10%	-35.24%	-33.67%	-39.34%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	6.94	6.94	7.58	7.39	6.94	7.58	7.39	7.39
2009 to 2011 change	-37.32%	-37.32%	-45.04%	-42.77%	-32.01%	-38.26%	-36.37%	-39.70%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.06	7.06	8.63	8.16	7.06	8.63	8.16	8.16
2009 to 2011 change	-28.68%	-28.68%	-31.84%	-30.70%	-13.50%	-10.32%	-11.00%	-19.38%
(a) Factor to convert 2009$ to 2011 $	1.0186							

Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discoiunt rate of 2.465%.

4.5. Avoided Gas Costs in Vermont

There is one LDC in Vermont, Vermont Gas Systems, Inc. (VGS). It receives its gas from TransCanada Pipeline at Highgate Springs, Vermont. The analysis of the avoided cost to the LDC in Vermont was performed similarly to that for the other two areas. Based on data provided by VGS, the source of gas was determined for each month of the year by the fraction contribution each month to serve firm customers.[101] Next, the avoided cost of natural gas to VGS by source for each month was computed, and then volume weighted to compute the average avoided cost of gas received at the city gate.

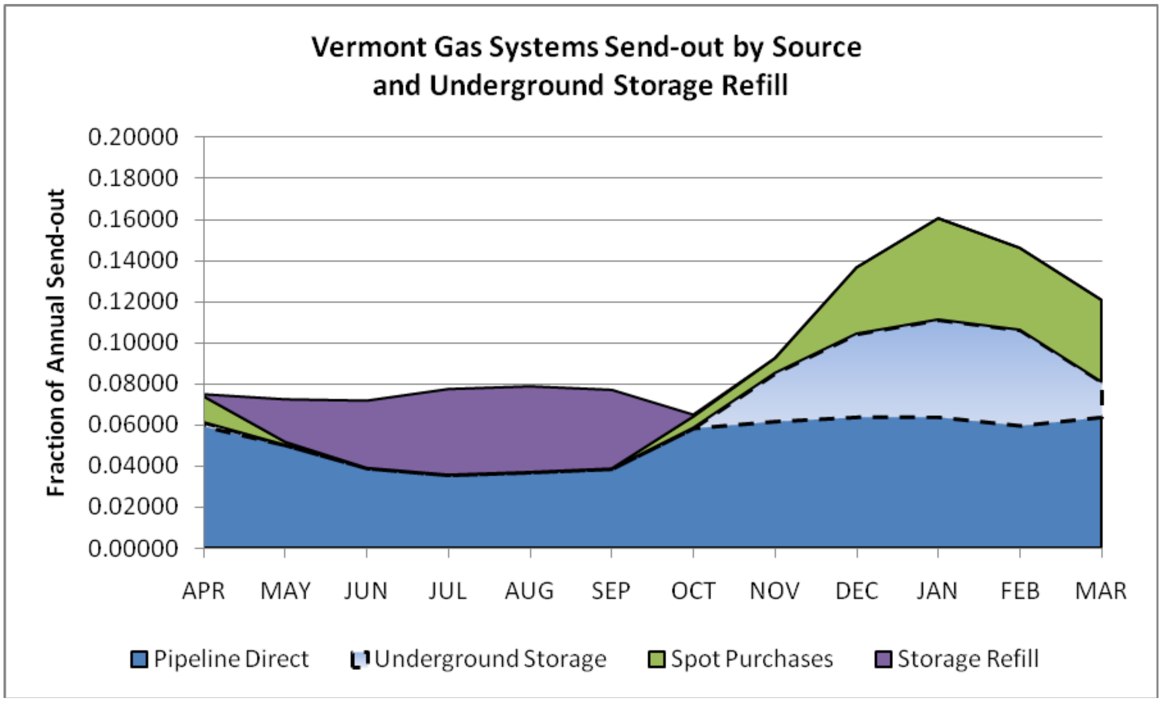
[101] This was data provided by VGS in early May 2011 supported by a recent purchased-gas-adjustment filing for 2011.

Each month, Vermont receives gas purchased in Alberta and transported by TransCanada Pipeline. During the winter months, November through March, Vermont also receives gas from underground storage and about an equal amount from purchases in spot markets. VGS has interruptible customers whom it serves using gas purchased in spot markets. During the winter, including April, when gas is needed to serve firm customers' peak loads, VGS interrupts its interruptible customers and delivers the spot gas thus released to its firm customers. Exhibit 4-19 shows the gas-supply characteristics of VGS as fractions while Exhibit 4-20 shows the gas supply by source each month and also storage refill.

Exhibit 4-19: Vermont Gas System: Monthly Sendout Fractions by Source, Peak Month, and Storage Injection

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual
Fractions of VGS Send-out by Source Each Month													
Pipeline Deliveries, Long-haul	81.1%	100.0%	100.0%	100.0%	100.0%	100.0%	91.5%	67.2%	47.0%	40.0%	41.1%	51.6%	63.6%
Underground Storage	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	25.2%	29.6%	29.4%	31.8%	15.9%	17.7%
Spot Purchases	18.9%	0.0%	0.0%	0.0%	0.0%	0.0%	8.5%	7.6%	23.4%	30.6%	27.2%	32.5%	18.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fraction of Annual Sendout each Month	7.4%	5.2%	3.9%	3.6%	3.7%	3.9%	6.4%	9.3%	13.7%	16.1%	14.6%	12.1%	100.0%
Monthly Sendout as a Fraction of Peak Month	46.0%	32.3%	24.4%	22.4%	23.2%	24.3%	40.0%	57.6%	85.1%	100.0%	91.0%	75.4%	
Fraction of Underground Storage Injection by Month	0.5%	11.7%	18.5%	23.6%	23.6%	21.6%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Basis, Parkway - HH, for spot price at Parkway	$0.50						$0.50	$0.50	$0.50	$0.50	$0.50	$0.50	
Sources:													
(a) Vermont Gas Systems.: May 2, 2011.													

Exhibit 4-20: Vermont Gas System Sendout by Source and Underground Storage Refill



Since this avoided-cost forecast was based on a forecast price of gas at the Henry Hub in Louisiana, the basis differential (price of gas in Alberta at the AECO hub minus the price at the Henry Hub) was computed from futures data on 26 May 2011 for the period June 2011 through May 2014 from the NYMEX for Henry Hub gas prices and from the Calgary based Natural Gas Exchange for the AECO-C hub prices. The exchange rate of US$ per CD$ was taken from the futures data on May 26, 2011 for June 2011 through September 2012 and averaged US$ 1.0149 per CD$. The average ratio of the Alberta gas price to the Henry Hub price in US$ is 0.899.[102]

The pipeline-transportation rates, rates for underground storage and transporting gas to VGS from underground storage, and the rates for transporting spot gas to VGS are used in the avoided cost forecasts. While the usage rates and fuel and loss percentages are about the same as in AESC 2009, the demand rates are more than twice those in AESC 2009. We assume these rates will prevail throughout the forecast period.

[102]This ratio is very similar to those in AESC 2007, winter 0.851 and summer 0.895 and in AESC 2009, winter 0.888 and summer 0.876.

Exhibit 4-21: Toll Rates of Vermont Gas Systems in 2011$

Canadian Tolls Paid by Vermont Gas Systems USD 2011 $								
		Demand (a) $/DT/Month		Usage $/DT		Fuel & Loss percent	
Firm Transportation							
	Long-Haul	$75.767	(a)	$0.171	(b)	3.14%	(c)
	From Storage	$15.957	(a)	$0.033	(b)	0.62%	(c)
Storage							
	Injection	$0.000		$0.000	(d)	2.93%	(d)
	Space	$1.229	(e)				
	Withdrawal	$0.000		$0.000	(d)	0.62%	(d)
Spot Gas Transportation							
	Parkway to Phillipsburg	$15.957	(a)	$0.033	(b)	0.62%	(c)
(a)	TransCanada Final Tolls effective Mar 1, 2011						
(b)	TransCanada Final Tolls effective Mar 1, 2011						
(c)	Average TransCanada actual fuel ratio for .Jun 2010 to May 2011						
(d)	VGS actual storage contract						
Note:	1 DT = 1 MMBtu = 1.055056 Giga Joules (GJ)						
	1 CD$ = 1.0472 US$ (3 month forward rate as of 29 April 2011)						
	Thus, US$/DT is calculated as 1.1049 of CD$/GJ						

Unlike other New England LDCs VGS uses long-haul transportation at about 100 percent load factor throughout the year with the summer refilling of underground storage and direct deliveries of gas to VGS. The increased requirements in the winter are served by underground storage and purchase and transportation of spot gas. The costs of underground storage include the costs of transportation of gas to fill storage, the cost of storage, and the cost of transportation from storage to VGS. However, demand charges for transporting stored gas in the winter are paid twelve months a year.

Purchases of gas in the spot market make up slightly more than 20 percent of the VGS gas supply. The prices of these spot purchases were estimated by VGS to be

US$0.50 greater than the Henry Hub price of gas. VGS transports spot gas with firm transportation, which means it pays demand charges 12 month a year but uses the capacity much less. Both for the transportation of spot and stored gas the demand charges are allocated by the months of higher usage to compute avoided costs by month as we have done for all the New England LDCs. The components of the avoided costs by the three sources of gas to Vermont are shown in Exhibit 4-22.

Exhibit 4-22: Avoided Cost From Three Sources of Supply

COMPARISON OF COSTS OF DELIVERING ONE DEKATHERM OF GAS TO VERMONT GAS SYSTEMS FROM THREE SOURCES OF NATURAL GAS and PEAK DAY			
		TransCanada Pipeline	
	units	January	June
Pipeline Long-haul to LDC			
Pipeline Demand Cost of Gas Delivered to LDC	2011 $/DT	$2.491	$0.000
Pipeline Usage Cost	2011 $/DT	$0.171	$0.171
Ratio of Gas Purchased in Alberta to Gas Delivered to LDC		1.032	1.032
Delivered From Underground Storage			
Pipeline Demand Cost of Gas Delivered to LDC	2011 $/DT	$1.915	
Pipeline Cash Variable Cost of Gas Delivered to LDC	2011 $/DT	$4.055	
Ratio of Gas Purchased to Gas Delivered to LDC		1.077	
Spot Purchases of Gas at Parkway			
Pipeline Demand Cost of Gas Delivered to LDC	2011 $/DT	2.430	
Pipeline Usage Cost	2011 $/DT	0.033	
Ratio of Gas Purchased to Gas Delivered to LDC		1.006	
Basis of Spot Gas Purchases: Parkway - HH	2011 $/DT	$0.500	
Peak Day in January From Underground Storage			
Pipeline Cash Demand Cost of Gas Delivered to LDC	2011 $/DT	$191.49	
Pipeline Cash Variable Cost of Gas Delivered to LDC	2011 $/DT	$4.055	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.077	
Based on pipeline tolls effective April 2011.			

We used this to estimate the avoided cost of natural gas delivered to VGS by month for the forecast period as shown in Appendix D. The AESC 2009 and AESC 2011 monthly avoided costs as levelized over fifteen years are shown in Exhibit 4-5. As in the other New England sectors, the average levelized avoided costs are slightly less in AESC 2011 in 2011 dollars because the price of gas at the

Henry Hub is less in 2011 than in 2009. However, the winter avoided costs of gas delivered to the city gate at VGS are higher in AESC 2011 during the winter months than in AESC 2009 despite the lower Henry Hub price because TransCanada has more than doubled its demand charges for pipeline transportation and Union's annual storage rates have increased since 2009. These increased demand charges are concentrated in the winter months because the annual demand charges for the transportation of stored gas and spot gas are all concentrated in the winter months. That is, if a DT of gas use is reduced in the winter months then the demand charges for those months and the summer months can be avoided.

Exhibit 4-5 is shown below for clarity.

COMPARISON OF THE LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO LDCs BY MONTH
FROM AESC 2009 AND AESC 2011

	Units		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual Average
SOUTHERN NEW ENGLAND: Gas Delivered via Texas Eastern and Algonquin Pipelines															
AESC 2009	2009$/DT	(a)	7.37	7.39	7.51	7.64	7.74	7.78	7.90	9.17	9.86	10.14	9.62	9.17	8.44
AESC 2009	2011$/DT	(b)	7.51	7.53	7.65	7.78	7.88	7.93	8.04	9.35	10.04	10.33	9.80	9.34	8.60
AESC 2011	2011$/DT	(c)	6.16	6.18	6.25	6.34	6.40	6.42	6.50	7.63	8.21	8.53	8.06	7.72	7.04
Percent Difference															
2009 to 2011			-17.9%	-17.8%	-18.2%	-18.6%	-18.8%	-19.0%	-19.1%	-18.3%	-18.2%	-17.4%	-17.7%	-17.3%	-18.2%
NORTHERN and CENTRAL NEW ENGLAND: Gas Delivered via Tennessee Gas Pipeline															
AESC 2009	2009$/DT	(a)	7.35	7.36	7.48	7.61	7.71	7.75	7.87	8.94	9.41	9.69	9.23	8.83	8.27
AESC 2009	2011$/DT	(b)	7.48	7.50	7.62	7.75	7.85	7.90	8.01	9.10	9.59	9.87	9.40	8.99	8.42
AESC 2011	2011$/DT	(c)	6.19	6.21	6.28	6.36	6.42	6.45	6.53	7.46	7.91	8.20	7.80	7.47	6.94
Percent Difference															
2009 to 2011			-17.3%	-17.2%	-17.6%	-17.9%	-18.2%	-18.3%	-18.5%	-18.0%	-17.4%	-16.9%	-17.1%	-16.9%	-17.6%
VERMONT GAS SYSTEMS: Gas delivered via TransCanada Pipeline															
AESC 2009	2009$/DT		6.36	6.21	6.38	6.49	6.57	6.61	6.71	8.09	8.57	9.24	8.77	8.28	7.36
AESC 2009	2011$/DT		6.48	6.33	6.49	6.61	6.69	6.73	6.83	8.24	8.72	9.41	8.93	8.44	7.49
AESC 2011	2011$/DT		5.61	5.42	5.48	5.55	5.60	5.63	5.77	8.77	9.22	9.80	9.34	8.50	7.06
Percent Difference															
2009 to 2011			-13.4%	-14.3%	-15.6%	-16.0%	-16.3%	-16.4%	-15.5%	6.5%	5.7%	4.2%	4.6%	0.7%	-7.2%

(a) AESC 2009 levelized costs over the 15-year period 2010 - 2024 with a discount rate of 2.218%.
(b) Factor to convert 2009$ to 2011$ 1.0186
(c) AESC 2011 levelized costs over the 15-year period 2012 - 2026 with a discount rate of 2.465%.

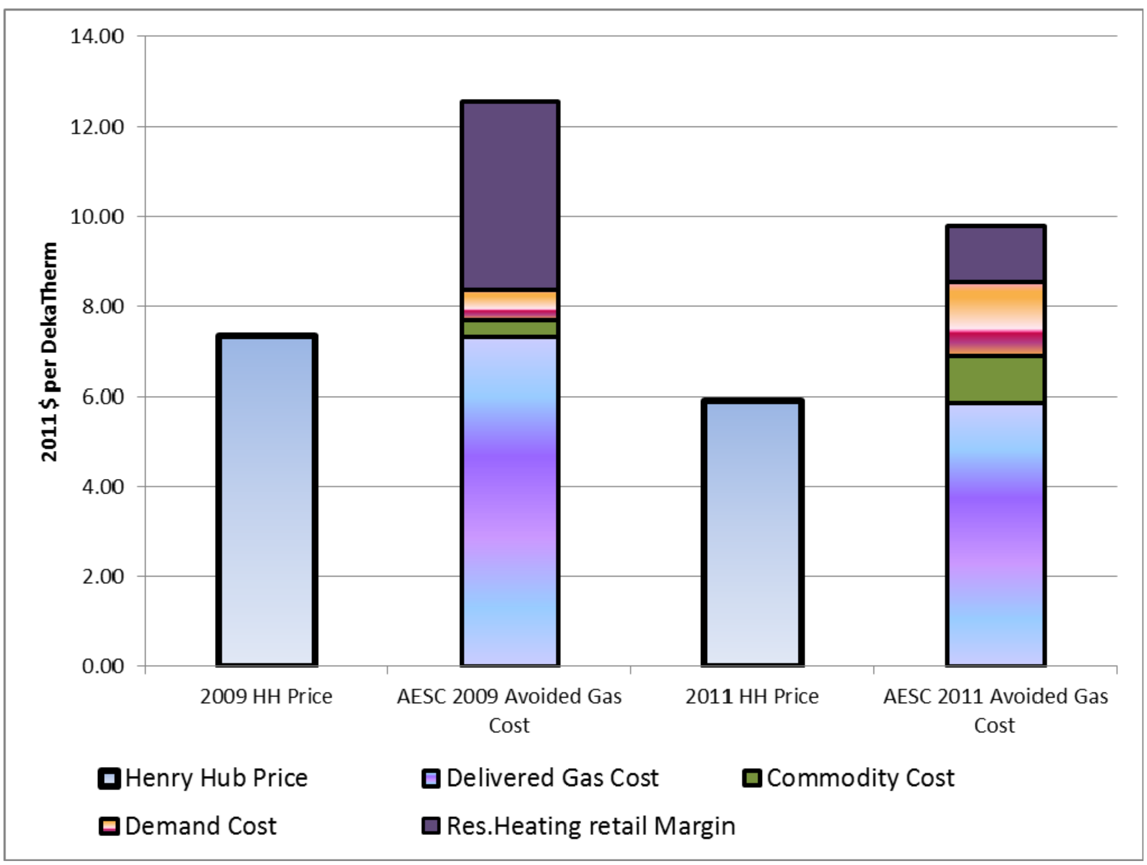
As in the other LDCs of New England, the avoided gas cost delivered to VGS's city gate by load type is shown in Appendix D. The retail avoided cost is the avoided gas cost delivered to the city gate of the LDC plus the LDC avoided margin. The LDC's avoided margin varies with load type; it is shown above in Exhibit 4-12. The avoided costs to the specified load types and customer sectors are shown in Appendix D.

The levelized avoided end use retail costs in Vermont are less than estimated in AESC 2009; see Exhibit 4-17 and Exhibit 4-18. The current retail end-use avoided cost assuming some retail margin is avoidable, in 2011 dollars, is lower than estimated in 2009 because in AESC 2011 we estimate the avoidable retail margin, if one exists, to be substantially less than in AESC 2009. The reason for this change is that the Study Group provided us with the margin costs in the LDC retail margin and it was estimated to be much less in 2011.

If one assumes that no retail margin is avoidable in AESC 2011then the avoided cost to the end user in AESC 2011 is the avoided cost at the city gate shown in Exhibit 4-18. As seen in Exhibit 4-18, with no retail margin in AESC 2011 but retaining the retail margin estimated in AESC 2009 the heating loads are reduced less than for the other states in New England or for the summer in VGS because of the much higher demand charges for transportation and for storage in 2011 compared with 2009.

Exhibit 4-23 shows the contribution to overall avoided cost to a heating customer by each of the components: cost of gas delivered to VGS, commodity costs of storing and delivering the gas, the demand cost of transporting gas, and the avoidable retail margin. This picture shows more clearly, the lower cost of gas in AESC 2011, offset by the higher commodity and demand costs of pipeline storage and transportation and the much lower avoided retail margin.

Exhibit 4-23: Comparison of the Components of the Avoided Cost to a Residential Heating Customer on Vermont Gas Systems in 2015 between AESC 2009 and AESC 2011



4.5.1. Peak Day Avoided Cost

As described above in the longer section on peak day avoided costs, we have included an estimate of peak day avoided costs, but we are unsure why such a measure applies. To the best of our knowledge, most or all efficiency improvements will reduce gas use throughout the year or the heating period. Other than interrupting interruptible load, which we understand VGS does, efficiency improvements reduce gas use whenever the equipment is in operation, not just on certain days. For this reason we estimate end-use avoided costs for base-load (high load factor) and heating load (low load factor) end use types because we assume that efficiency improvements exist whenever the equipment is in operation. But the avoided costs apply over periods of several months as seen in the load profiles of Exhibit 4-10.

Nonetheless, we have earlier in this Chapter estimated peak-day costs as the cost of taking gas from underground storage to be used only for one day while paying the relevant demand charges for 12 months. For VGS, as shown in Appendix D, the avoided cost so calculated and levelized over 15 years, 2012-2026, is $201.16 per Dekatherm.

However, this method of computing peak-day avoided costs, while useful when estimated a peak-day cost for a number of LDCs, is probably better done by examining the particular facts and circumstances of a single LDC, such as VGS. While we have not examined the method and estimates in detail, it is our understanding that because VGS is growing, VGS estimates peak-day costs as the avoided cost of transmission looping on its own system plus the associated carrying costs and upstream avoided supply costs. This appears reasonable.

Similarly, we understand that VGS estimates the avoided cost during its peak period, which is longer than one day, as the variable cost of the propane in its propane-air facilities. This seems to be reasonable as long as the cost of propane is the highest cost alternative supply during the peak period.

4.6. Value of Environmental Impacts of Natural Gas Combustion

4.6.1. Pollutants Created by Combustion of Natural Gas and their Significance

Natural gas consists of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inert gases (typically nitrogen, carbon dioxide, and helium) (EPA 1999). In general the combustion of natural gas in boilers and furnaces generate the following pollutants (EPA 1999, 1.4-2–5):

- Oxides of nitrogen (NO_x)

- Trace levels of sulfur oxides (SO_x)[103]
- Carbon dioxide and other greenhouse gases
- Trace levels of particulates
- Volatile organic compounds
- Carbon monoxide

The most significant of these pollutants are carbon dioxide and oxides of nitrogen. These two pollutants were determined to be the most significant based on the fact that the absolute quantities of each resulting from the combustion of natural gas are large relative to the absolute quantity of each from all sources. In other words, combustion of gas is a major source of these pollutants.

To estimate the absolute quantities of each pollutant from the combustion of natural gas relative to the absolute quantity of each from all sources we began by estimating the quantity of each that is emitted per MMBtu of fuel consumed. Exhibit 4-24 provides emissions factors for NO_x and CO_2 for on three generalized boiler type categories.

Exhibit 4-24: Emission Rates of Significant Pollutants

Boiler Type	NO_x (lbs/MMBtu)	CO_2 (lbs/MMBtu)
Residential boilers	0.0922	118
Commercial boilers	0.0980	118
Industrial boilers	0.137	118

Notes:
NO_x emissions from industrial boilers without low NO_x burners would be 0.274 lb/MMBtu. We assumed these boilers were controlled in order to be conservative.
NO_x and CO_2 emissions factors for all boilers utilized conversion rate of 1,020 Btu/scf
Sources:
Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. http://www.epa.gov/ttnchie1/ap42/

We apply these pollutant emission rates to the quantity of natural gas consumed, by sector, in New England in 2007. The estimated annual quantity of each of the two pollutants from natural-gas combustion, and from other sources, is presented in Exhibit 4-25.

[103] Sulfur is generally added as an odorant to natural gas, which generates trace quantities of sulfur oxides when combusted.

Exhibit 4-25: Pollutant Emissions in New England from Natural Gas

Sector	NO_x (tons)	CO_2 (tons)
Combustion of Natural Gas in R, C & I		
Residential	9,518	12,181,966
Commercial	6,858	8,257,699
Industrial	7,173	6,178,126
R, C & I Total	***23,549***	***26,617,791***
Emissions from Electric Generation		
	87,000	***38,800,000***

Notes
All figures are for 2009 except emissions from electric generation, which are from 2008.
Source
Energy Information Administration
http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm
Environmental Protection Agency http://www.epa.gov/ttn/chief/net/2008inventory.html

This table illustrates that combustion of natural gas is a major source of each of these pollutants. Moreover, those emissions are not currently subject to regulation, as explained below.

- *CO_2.* Regional Greenhouse Gas Initiative (RGGI) applies to electric generating units larger than 25 MW. New England CO_2 emissions for 2008 were 38.8 million tons. The total CO_2 emissions from the end-use sectors above would represent about 41 percent of the total CO_2 emissions, if such emissions were included.
- *NO_x.* The Ozone Transport Commission/EPA NO_x budget program applies to electric generating units larger than 15 MW and to industrial boilers with a heat input larger than 100 MMBtu/hour. New England NO_x emissions for 2008 were approximately 87,000 tons for just the electric generating sector[104]. The total NO_x emissions from the end use sectors above would represent about 21% of the total NO_x budget if such emissions were included.

[104] A few large sources in the industrial sector are included in the NOx budget program. These include municipal waste combustors, steel and cement plants, and large industrial boilers (such as those located at Pfizer in, New London, CT and General Electric in, Lynn, MA). However, the number of NO_x allowances used, sold, and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold and traded for electric generating units.

4.6.2. Value Associated With Mitigation of Each Significant Pollutant

We estimate the value associated with mitigation of NO_x and CO_2 based on the 2011 emissions allowance prices per short ton presented in Exhibit 2-3.[105] This approach, which is consistent with AESC 2009, represents a consistent application of emission allowance prices across all fuels. As noted previously, natural-gas combustion is not a significant source of SO_2 emissions. Consequently we have not included an emission value for SO_2.

In addition, we provide a value of reducing CO_2 based upon the $80/ ton long-term marginal abatement cost of carbon dioxide reduction. States that have established targets for climate mitigation comparable to the targets discussed in Chapter 6, or that are contemplating such action, could view the $80/ton long-term abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of reductions in carbon emissions required to achieve those targets. This value is described in greater detail in Chapter 6 (Section 6.6.4.2).

The annual pollutant-emission values by end-use sector are summarized below in Exhibit 4-26. They equal the pollutant allowance prices multiplied by the pollutant emission rates.

[105] The full externality value associated with NO_x emissions is probably not captured in the allowance price from electricity generation, however determining that externality value is beyond the scope of this project.

Exhibit 4-26: Annual Pollutant Emission Values in 2011$/MMBtu

Pollutant Emission Values by Sector and by Year in 2011$/MMBtu									
	Residential			Commercial			Industrial		
	NOx	CO2	CO2 at $80/ton	NOx	CO2	CO2 at $80/ton	NOx	CO2	CO2 at $80/ton
2011	$0.011	$0.11	$4.72	$0.011	$0.11	$4.72	$0.016	$0.11	$4.72
2012	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2013	$0.006	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2014	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2015	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2016	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2017	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2018	$0.007	$0.90	$4.72	$0.007	$0.90	$4.72	$0.010	$0.90	$4.72
2019	$0.007	$1.08	$4.72	$0.008	$1.08	$4.72	$0.011	$1.08	$4.72
2020	$0.007	$1.25	$4.72	$0.008	$1.25	$4.72	$0.011	$1.25	$4.72
2021	$0.007	$1.43	$4.72	$0.008	$1.43	$4.72	$0.011	$1.43	$4.72
2022	$0.008	$1.60	$4.72	$0.008	$1.60	$4.72	$0.011	$1.60	$4.72
2023	$0.008	$1.78	$4.72	$0.008	$1.78	$4.72	$0.012	$1.78	$4.72
2024	$0.008	$1.96	$4.72	$0.008	$1.96	$4.72	$0.012	$1.96	$4.72
2025	$0.008	$2.13	$4.72	$0.009	$2.13	$4.72	$0.012	$2.13	$4.72
2026	$0.008	$2.31	$4.72	$0.009	$2.31	$4.72	$0.012	$2.31	$4.72
Levelized (2011$/MMBtu)									
5 year (2012-16)	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
10 year (2012-21)	$0.007	$0.50	$4.72	$0.007	$0.50	$4.72	$0.010	$0.50	$4.72
15 year (2012-26)	$0.007	$0.93	$4.72	$0.008	$0.93	$4.72	$0.011	$0.93	$4.72

Notes

Based on Exhibit 4-24 pollution emission rates for Natural Gas combustion

Pollutant values based on emission allowance prices detailed in Exhibit 2-3 and $80/short ton long-term marginal abatement cost for CO2

The entire amount of each value is an externality. With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of these emissions are currently subject to environmental requirements. Therefore, none of these values are internalized in their market prices.

Chapter 5: Forecast of New England Regional Oil Prices and Avoided Cost of Other Fuels by Sector

5.1. Introduction

This chapter details the development of a forecast of prices for petroleum products used in electric generation as well as in the residential, commercial and industrial sectors in New England. For AESC 2011, we develop forecast prices for three fuel oil grades, i.e., No. 2, No. 4 and No. 6 and two biofuel blends, B5 and B20 (and also the projection of coal prices for the electric sector.) In addition, we develop a forecast of unit fuel oil costs that would be avoided by the installation of oil-saving energy efficiency measures in the commercial, industrial, and residential sectors.

AESC 2011 requires the development of avoided costs by state, if supported by research, and for other fuels used in residential heating applications. For AESC 2011, these other fuels are wood, wood chips or pellets, kerosene and propane.

Our proposed AESC 2011 forecasts for crude oil and fuels by sector and region are presented in detail in Appendix E.

The current forecast of fuel prices for residual oil is on average 3.2 percent lower than the AESC 2009 forecast over a fifteen-year period. All other fuels (distillate, kerosene, propane, biofuel, and wood) are on average higher than those of AESC 2009 by approximately 11.0 percent.

Exhibit 5-1: Summary of Other Fuel Prices: AESC 2011 Forecast versus AESC 2009

	No. 2 Distillate	No. 2 Distillate	No. 6 Residual (low Sulfur)	Propane	Kerosene	BioFuel	BioFuel	Wood
Sector	Res	Com	Com	Res	Res & Com	B5 Blend	B20 Blend	Res
AESC 2011 Levelized Values (2011$/MMBtu)								
2012-2026	25.37	23.53	17.26	36.00	25.50	25.37	25.37	9.47
AESC 2009 Levelized Values (2011$/MMBtu)								
2010-2024	23.25	22.09	17.85	34.66	22.59	23.25	23.25	8.38
Percent Difference from AESC 2009								
	9.1%	6.5%	-3.3%	3.9%	12.9%	9.1%	9.1%	13.0%

Notes
Res = Residential Sector
Com = Commercial Sector

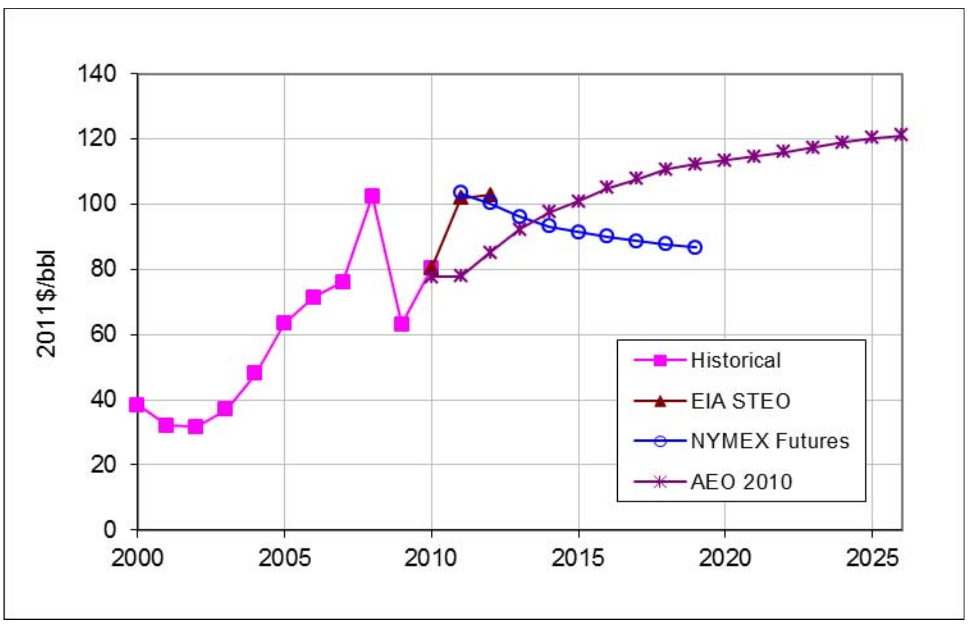
5.2. Forecast of Crude Oil Prices

Our general approach to develop the forecasts of crude-oil prices and of Henry Hub natural-gas prices is to use a set of relevant NYMEX futures prices in the near term, e.g. the first three to five years, and the relevant EIA Annual Energy Outlook forecast in the long term. This approach is based upon our view that futures market prices are the most-accurate estimates in the near term while projections from a forecasting model that reflects long-term demand and supply fundamentals, such as the EIA's National Energy Modeling System, are the most accurate estimates in the long term. As in AESC 2007 and AESC 2009, we develop our forecast of petroleum product prices based on the approach, i.e., NYMEX futures for West Texas Intermediate in the first five years and EIA's reference-case-forecast prices in following years.

Based on that general approach, our first step in developing a forecast of crude oil prices was to review the EIA Reference Case forecast (2010a). However, there is considerable uncertainty regarding the future price of crude oil.

We next compared EIA's (2010a) reference-case-forecast prices in the near term, i.e. 2011 through 2014, with current NYMEX futures prices for West Texas Intermediate (WTI).[106] This comparison revealed a significant difference between NYMEX futures for WTI in the near-term and EIA's reference-case-forecast prices in the near-term. That disparity is presented in Exhibit 5-2, which plots, in 2011 dollars per bbl, 1) actual oil prices since 2000, 2) WTI futures through 2019, and 3) EIA's (2010a) reference-case-forecast prices through 2026.

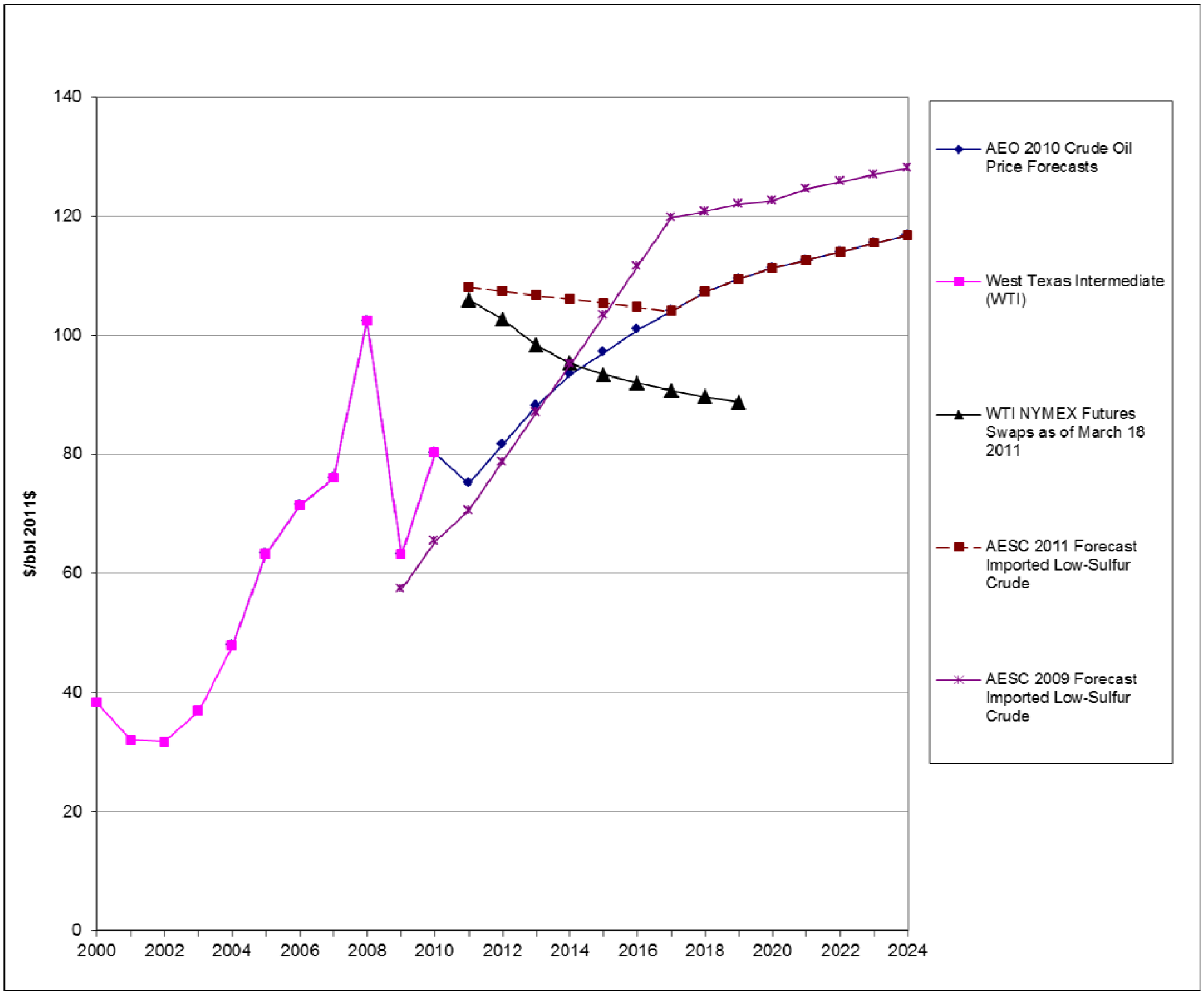
Exhibit 5-2: Low-Sulfur-Crude Prices, EIA vs. NYMEX (2011$ per bbl)



[106]NYMEX prices as of March 18, 2011. WTI was used for this comparison because it is actively traded and its price in the past has been very close to that of the low-sulfur light crude used in EIA's Reference Case.

Based on both the NYMEX futures and the latest EIA Short-Term Energy Outlook (STEO) we conclude that there have been significant changes in the oil markets that will likely continue and were not foreseen when the AEO 2010 forecast was produced in late 2009 and early 2010. The longer term forecast prices are fairly close to the current market prices. Thus, we use the EIA STEO prices for 2011 and 2012 and then transition to the AEO 2010 price in 2014 by using the NYMEX 2013 price. This forecast projects a slight dip in prices in 2013 and 2014 followed by a gradual rise. With the release of AEO 2011, we reviewed the AEO 2011 crude oil forecast and found that the only significant differences were in the first two years, after which the price forecast was more or less the same as AEO 2010. Since we do not use the near term AEO projections in our own forecast, we feel comfortable continuing to use the AEO 2010 projections. The AESC 2011 forecast is higher than the AESC 2009 forecast in the years prior to 2015, but lower thereafter. Exhibit 5-3 depicts the AESC 2011 forecast and the AESC 2009 forecast in addition to the data from Exhibit 5-2.

Exhibit 5-3: Low-Sulfur-Crude Actual and Forecast Prices (2011$ per bbl)



5.3. Forecast of Electric-Generation Fuel Prices in New England

The EIA (2010a) provides forecasts of regional prices for distillate, residual, and coal for electricity generation in New England.

5.3.1. Forecast Prices of Distillate and Residual

The EIA (2010a) provides forecasts for prices of distillate and residual for electricity generation in New England. We began by calculating the forecast unit margin implicit in EIA's (2010a) forecast of those prices as a ratio to the corresponding crude oil price forecast, and comparing those ratios to the historical unit margins. That comparison indicates that the forecast margins are generally consistent with the historical margins.

Our analysis did not identify material differences by state in the historical prices for these fuels in this sector. Therefore, we developed a forecast of these prices by multiplying the corresponding EIA (2010a) forecast price each year times the ratio of our crude-oil forecast to the EIA (2010a) crude-oil forecast.

5.3.2. Forecast Prices of Coal

The EIA (2010a, Table 78) Reference Case forecasts fairly slightly declining prices for coal in New England. We consider this reasonable. The U.S. has substantial coal resources and coal prices have been relatively stable over a long time period without the volatility seen in oil and natural gas prices. While coal at the mine mouth is relatively cheap on an energy basis, it is expensive to transport and to burn. Coal demand is also unlikely to increase significantly because of various environmental concerns. Coal is more expensive in New England because of the transportation costs and represents a smaller fraction of annual electric generation than most other parts of the U.S. Since EIA's coal prices are essentially flat and consistent with historical experience and market behavior, we use them for AESC 2011.

5.4. Forecast of Petroleum Prices in the Residential, Commercial, and Industrial Sectors

The EIA (2010) provides forecasts of regional prices for distillate and residual fuel oil in the residential, commercial, and industrial sectors in New England. The retail price of each fuel in each sector of a given state can be separated into two major components. The first component is the price of the underlying resource, crude oil. The second component is a margin, or the difference between the price of each fuel at the retail level and the crude oil price. The margin represents the aggregate unit costs of the refining process, distribution, and taxes attributed to the particular fuel by sector and state. We developed our forecast of prices for fuels in each of these sectors in the following three steps, and detailed in the following sub-sections:

- First, we calculate the forecast unit margin implicit in EIA's (2010) forecast of the New England regional price for each fuel, expressed as a ratio to the crude oil price, and compare it to the historical unit margin, calculated from historical price data. We develop a modified New England price for any fuel with an EIA (2010) forecast margin that we find unreasonable based on historical trends;
- Second, we derive regional forecasts of New England prices for each fuel by multiplying the corresponding EIA (2010) forecast, as may be modified in step one, by the ratio of our crude-oil forecast (as detailed in Section 0) to the EIA (2010) crude-oil forecast;

- Finally, we develop our forecast of prices for each fuel by New England state from the regional forecast to the extent that historical prices for that fuel have differed materially by state.

Our analysis finds material differences by state in the historical prices for some fuels in these sectors. Therefore, we adjust the corresponding EIA (2010) regional forecasts of distillate and residual by the ratio of the AESC 2011 forecast of crude oil and EIA's (2010) forecast of crude oil. We then develop a forecast of prices for each fuel by New England state from the regional forecast.

5.4.1. New England Regional Prices by Sector

The forecast of regional prices by fuel and sector in New England is presented in Appendix E.

We derive forecasts of regional petroleum product prices by adjusting the corresponding EIA (2010) forecasts of product prices in proportion to the ratio of our crude oil forecast to the EIA's (2010) crude oil forecast. This approach is based upon our conclusion that crude oil is the dominant component of petroleum product prices and that preparing a forecast of future absolute margins by product based upon historical absolute margins is beyond the scope of this project.

In summary, our proposed AESC 2011 forecasts of regional prices of petroleum and related products by sector is based on the following approaches:

- No. 2 and 6 Fuel Oil: EIA (2010) forecast of regional product price adjusted for ratio of AESC 2011 crude oil forecast to EIA (2010) crude oil forecast;
- No. 4 Oil: no projection. No. 4 is a blend of distillate and residual and we had no data on the relative proportions of that blend;
- B5 and B20: our forecast of corresponding petroleum-product prices.

For No. 2 and 6 fuels, we first calculate the forecast unit margins implicit in the EIA (2010) forecast of those prices as a ratio to the corresponding crude oil price forecast. Next, we compare the average ratio for each fuel in each sector to the corresponding historical unit margins. That comparison indicates that the forecast margins are generally consistent with the historical margins. Based upon the results of that comparison, we develop our forecast of these prices by multiplying the corresponding EIA (2010) forecast price each year by the ratio of our crude oil forecast to the EIA (2010) crude oil forecast.

The EIA (2010) does not provide a forecast of New England regional prices for biofuels B5 and B20. We therefore prepared an independent analysis. B5 and B20 are each a mix of a petroleum product, such as distillate oil or diesel, and an oil-like product derived from an agricultural source (e.g. soy beans). The number in their name is the percent of agricultural-derived component. Thus “B5” and “B20” represent products with a five percent and a 20 percent agricultural-derived component, respectively. They are both similar to No.-2 fuel oil and used primarily for heating. Each of these fuels has both advantages and disadvantages relative to No. 2 fuel oil. Their advantages include lower greenhouse-gas emissions per MMBtu of fuel consumed, more efficient operation of furnaces, and less reliance on imported crude oil. Their disadvantages include somewhat lower heat contents and concerns about the long-term supply of agricultural source feedstocks. A comparison of prices for biodiesel and regular diesel published by the DOE Alternative Fuels and Advanced Vehicles Data Center shows that, on a heat rate basis, the price differentials for these blends have varied slightly above, and slightly below, the prices for regular diesel.[107] In 2008, the premium for B2-B5 blends varied from negative three (-3) percent to five percent over regular diesel prices. In 2010, the premium for B20 has varied from three percent to five percent above diesel fuel prices. Based upon the limited experience with these fuels to date, and their premium and sub-premium attributes relative to their comparable petroleum products, we have no basis for projecting prices materially different from their competing petroleum products. Thus, we forecast the prices of biofuels to be the same on an energy basis as diesel.

Since crude oil prices do not show significant variations by month or season, we have not developed monthly or seasonal price variations for petroleum products. Storage for petroleum products is relatively inexpensive and this also tends to smooth out variations in costs relative to market prices. For these reasons, and those presented in the Chapter Three discussion of volatility in natural gas prices, our forecast does not address volatility in the prices of these fuel prices.

5.4.2. Weighted Average Avoided Costs by Sector Based on Regional Prices

We develop weighted average costs of avoided petroleum related fuels by sector by multiplying our projected regional prices for each fuel and sector by the relative quantities of each petroleum related fuel that EIA (2010) projects will be used in that sector. The relative quantity of each petroleum related fuel that EIA (2010) projects for each sector, expressed as percentages, are presented in

[107] The DOE stopped reporting B2-B5 as a separate fuel category after April 2009, and instead includes it in its diesel price. We therefore focus our analysis for B2-B5 fuel on the 2008 data, and for B20 on the 2010 data, with the caveat that as the 2010 diesel price data includes B2-B5 prices, a direct comparison between 2010 and 2008 is not possible. Data for B2-B5 from *Clean Cities Alternative Fuel Price Report* 1/08, 4/08, 7/08, 10/08, 1/09. Data for B20 from *Clean Cities Alternative Fuel Price Report* 1/10, 4/10, 7/10, 10/10, 1/11.

Appendix E. The resulting weighted average costs of avoided petroleum related fuels by sector are presented in Appendix E.

We estimate that the crude oil price component of these projected prices is the portion that can be avoided.

5.4.3. Prices by State by Sector

To determine if there were material differences by state in the historical prices for any of these fuels in these sectors, we analyzed the actual prices by sector in each state from 1999 through 2008 using data from the EIA State Energy Data System (SEDS). This is the most complete and consistent source of state-level energy prices.

We used Massachusetts prices as the reference point for each sector. We calculated the difference between prices in other states with the prices in Massachusetts for each year in each sector. The metric we used to determine if those differences were material was the ratio of the mean difference to the standard deviation. If that ratio was greater than 2 we concluded that the differential was material. Using that test we found material differences between some states in:

- Distillate fuel oil prices in the commercial (Rhode Island, Vermont) and residential (New Hampshire) sectors;
- Liquefied Petroleum Gas (LPG) prices in the commercial (Connecticut, New Hampshire, Rhode Island) and residential (Maine, New Hampshire, Rhode Island, Vermont) sectors;
- Residual fuel oil prices in the commercial and industrial sectors (New Hampshire).

Given the uncertainty associated with future quantities of fuel use by state by sector, and future policies on fuel taxes by state by sector, and other uncertainties, we conclude no further precision would be obtained from an estimate of avoided petroleum related fuel prices by sector by state.

5.5. Avoided Costs of Other Residential Fuels

For wood and kerosene, we determined the historical average ratio between the price of each fuel and the price of distillate in the residential sector from EIA SEDS data. These resulting ratios were 0.37 for wood and 0.99 for kerosene.[108] Then we derived the forecast of regional prices for each of those fuels by

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[108] EIA State Energy Data System, http://www.eia.doe.gov/emeu/states/_seds.html (accessed 5/3/2011).

multiplying our AESC 2011 forecast price of distillate in the residential sector each year by the historical ratio.

The wood values are for cordwood.[109] Values for wood pellets would be approximately twice as high according to the limited data on wood prices.[110] Vermont publishes prices for cord wood and wood pellets, [111] but other New England states do not, relying instead upon prices reported by EIA. Based on these factors, we used the EIA SEDS data to develop prices for cordwood in New England.

For propane, we draw upon the EIA (2010) forecast of New England regional prices. The AESC 2011 forecast is derived from the EIA (2010) regional forecast by multiplying it times the ratio of the AESC 2011 crude oil forecast and the EIA (2010) crude oil forecast.

Our forecasts of prices for each fuel are presented in Appendix E. All prices are reported in constant 2011 dollars per MMBtu except where noted.

5.6. Environmental Impacts

We estimate the environmental benefit from reduced combustion of fuel oil due to energy efficiency programs with the following analyses:

- Identifying the various pollutants created by the combustion of fuel oil, assess which of them are significant and how, if at all, the impact of those pollutants is currently internalized into the cost of fuel oil.
- Finding the value associated with mitigation of each significant pollutant and portion that should be treated as an externality.

The pollutant emissions associated with the combustion of fuel oil are dependent on the fuel grade and composition, boiler characteristics and size, combustion

[109] Residential customers can purchased either cord wood or wood pellets. Despite our attempts, we were unable to obtain a statistically valid set of historical prices for wood pellets by state other than Vermont.

[110] The Vermont cord wood price data is consistent with the EIA SEDS data, although somewhat higher. The wood pellet prices are higher than the cord wood prices but the time series of wood pellet prices is limited and the survey used to collect that data is informal.

[111] The Vermont Department of Public Service publishes prices for cordwood and wood pellets collected by the Vermont Department of Forests through an informal survey each month. http://publicservice.vermont.gov/pub/vt-fuel-price-report.html

process and sequence, and equipment maintenance (EPA 1999 1.3-2). In general, these pollutants (EPA 1999 1.3-2 to 1.3-5) are as follows:[112]

- Oxides of nitrogen (NO_x)
- Sulfur oxides
- Carbon dioxide and other greenhouse gases
- Particulates
- Trace elements
- Organic compounds
- Carbon monoxide

Of those pollutants, oxides of nitrogen, sulfur oxides, and carbon dioxide are potentially the most significant.[113] Oxides of nitrogen are precursors to the unhealthy concentrations of ozone that many areas in New England continue to experience. The region is also required to reduce NO_x and SO_x emissions by EPA programs, and the RGGI program requires mandatory reductions of CO_2 from the power sector.[114]

The value of mitigating emissions of NO_x, SO_x, and CO_2 in the electrical generation sector from the combustion of these fuels can be estimated using the forecast of emissions allowance prices presented in Exhibit 2-3 of Chapter 2.

5.6.1. Significance of Air Emissions from Combustion of Fuels by Sector

To estimate the absolute quantities of each pollutant from the combustion of fuels by sector we began by estimating the quantity of each pollutant that is emitted per MMBtu of fuel consumed.[115] The pollutant emissions associated with the

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[112] EPA, 1999. "Stationary Point and Area Sources" v. 1 of Compilation of Air Pollutant Emission Factors 5th Ed. AP-42. Triangle Partk, N.C.: U.S. Environmental Protection Agency.

[113]Wood combustion may contribute to an accumulation of unhealthy concentrations of fine particulate matter ($PM_{2.5}$). This is especially true in many valleys, where pollutants accumulate during stagnant meteorological conditions. The regulation of $PM_{2.5}$ from wood combustion is a state by state process. No comparable regionally consistent or market-based program of allowances have been established for $PM_{2.5}$, like those described above for SO_x, NO_x, and CO_2.

[114] SO_2 and NO_X emissions are regulated by the EPA under the acid rain program and the regional NOX budget trading program, as well as the new Clean Air Interstate Rule. CO_2 emissions from electrical generation sources are regulated under the Regional Greenhouse Gas Initiative (RGGI).

[115]Number-6 fuel oil has about the same rate of SO_2 emissions as distillate, about twice the rate of NO_x emissions and about seven percent higher rate of CO_2 emissions.

combustion of wood are dependent on the species of wood, moisture content, appliance used for its combustion, combustion process, and sequence and equipment maintenance. The pollutant emissions associated with the combustion of kerosene are similar to those associated with the combustion of distillate oil, and depend upon boiler characteristics and size, combustion process and sequence, and equipment maintenance (EPA 1999, 1.3-2).

Exhibit 5-4 below provides emissions factors for each fuel based on three generalized boiler-type categories.

Exhibit 5-4: Emission Rates of Significant Pollutants from Fuel Oil

Boiler type, and fuel combusted	SO_x (lbs/MMBtu)	NO_x (lbs/MMBtu)	CO_2 (lbs/MMBtu)
#2 Fuel Oil			
Residential boiler, combusting #2 oil	0.152	0.129	173
Commercial boiler, combusting #2 oil	0.152	0.171	164
Industrial boilers, combusting #2 oil	0.304	0.171	161
Kerosene—Residential heating	0.152	0.129	173
Wood—Residential heating	0.468	2.59	N/A

Notes:
For industrial boilers: assumed sulfur content = 0.3% by weight
For residential and commercial boilers: assumed sulfur content = 0.15% by weight
Kerosene same as Residential # 2 oil

Sources:
1) Energy Information Administration, Electric Power Annual with data for 2009. Table A3 *http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html* (for CO_2 for industrial boilers)
2) Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. *http://www.epa.gov/ttnchie1/ap42/* (for SO_x and NO_x emissions factors for all boilers)
3) Environmental Benefits of DSM in New York: Long Island Case Study; Bruce Biewald and Stephen Bernow, Tellus Institute. Proceedings from Demand-Side Management and the Global Environment, Arlington, Virginia, April 22-23, 1991. (for CO2 emissions factors for residential and commercial boilers)
4) James Houck and Brian Eagle, OMNI Environmental Services, Inc, Control Analysis and Document for Residential Wood Combustion in the MANU-VU Region, December 19, 2006. (for wood)

Emissions values for fuel oil and kerosene were based on AESC 2009 values and updated with EIA data. The values for emissions from wood remain unchanged from the AESC 2009 values. Next, we applied those pollutant emission rates to the quantity of each fuel consumed by sector in New England in 2009.[116]

[116] Distillate fuel oil consumption figures for 2009 come from the Energy Information Administration (http://www.eia.doe.gov/emeu/states/sep_fuel/html/fuel_use_df.html). No more appropriate up to date

Exhibit 5-5: Distillate Consumption, 2009 (Trillion BTU)

Residential	Commercial	Industrial
242	60	23

Combustion of No. 2 fuel oil is a major source of each of these pollutants but kerosene and wood are not, as seen Exhibit 5-6 below.

Exhibit 5-6: Pollutant Emissions in New England by Major Source

	Sector	SO_2 (tons)	NO_x (tons)	CO_2 (tons)
Emissions from Electric Generation				
A		**87,000**	**20,000**	**38,800,000**
Combustion of #2 Fuel Oil in R, C & I				
I	Residential	18,440	15,583	20,967,600
Ii	Commercial	4,526	5,100	4,879,000
Iii	Industrial	3,530	1,989	1,867,600
B = i + ii +iii	**R, C & I Total**	**26,496**	**22,672**	**27,714,200**
C	**Combustion of kerosene in Residential heating**	**1,392**	**434**	**1,104,660**
D	**Combustion of wood in Residential heating**	**556**	**3,081**	**N/A**
E = A + B + C + D		**115,444**	**46,187**	**67,618,860**
Non-electric as percent of total (B+C+D)/E		**25%**	**57%**	**43%**
Notes				
All figures are for 2009 except SO_2 and NO_x for emissions from electric generation, which are from 2008.				

5.6.2. Value of Mitigating Each Significant Pollutant

Emissions of NO_x, SO_x, and CO_2 from the combustion of these fuels are not currently subject to regulation, as explained below.

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resource for kerosene or wood consumption figures could be found, and so we use the same values as in the AESC 2009 report.

- SO_2 & CO_2: The acid rain program and Regional Greenhouse Gas Initiative (RGGI) apply to electric generating units larger than 25 MW. New England SO_x emissions from electric generating units for 2008 were approximately 87,000.[117] The total SO_x emissions from the end-use sectors above would represent approximately 35 percent of the total SO_x emissions, if such emissions were included. New England electric generation CO_2 emissions for 2009 were 38.8 million tons. The calculated CO_2 emissions from the end-use sectors above would represent approximately 43 percent of the total electric generation CO_2 emissions, if such emissions were included.
- NO_x: The Ozone Transport Commission–EPA NO_x budget program applies to electric generating units larger than 15 MW and to industrial boilers with a heat input larger than 100 MMBtu per hour. New England NO_x emissions for 2008 were approximately 80,000 tons for just the electric generating sector[118]. The total NO_x emissions from the end use sectors above would represent approximately 57 percent of the total NO_x budget if such emissions were included.

We base the value associated with mitigation of NO_x, SO_x, and CO_2 on the 2011 emissions allowance prices per short ton in Exhibit 2-3 in Chapter 2 and the externality value of CO_2 shown in Exhibit 6-56 from Chapter 6. This approach, which is consistent with AESC 2009, applies the allowance prices for NO_x, SO_x, and CO_2 consistently across fuels. In addition, for CO_2 we have provided the value of pollutant emissions associated with the sustainability target value of $80/ short ton.

The pollutant-emission values for 2011 based upon these allowance prices and the pollutant emission rates, as presented in Exhibit 5-4, are presented in Exhibit 5-7.

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117 The most recent data from the EPA for New England SO_2 and NO_x emissions levels is from 2008.

118 A few large sources in the industrial sector are included in the NO_x budget program. These include municipal waste combustors, steel and cement plants and large industrial boilers (such as those located at Pfizer in New London, Connecticut, and General Electric, in Lynn, Massachusetts). However, the number of NO_x allowances used, sold and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold and traded for electric generating units.

Exhibit 5-7: Value of Pollutant Emissions from Fuel Oil in 2011

Generalized Boiler Type by Sector	SO_2 (\$/MMBtu)	NO_x (\$/MMBtu)	CO_2 (\$/MMBtu)	CO_2 at \$80/ton (\$/MMBtu)
Residential boiler	0.0003	0.0148	0.1635	\$6.92
Commercial boiler	0.0003	0.0197	0.1550	\$6.56
Industrial boiler	0.0006	0.0197	0.1521	\$6.44

The emission values in Exhibit 5-7 are an externality.[119] With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of the emissions shown in Exhibit 5-6 are currently subject to environmental requirements. [120] None of these values, therefore, are currently internalized in the relevant fuel's market prices. States that have established targets for climate mitigation comparable to the targets discussed in Chapter 6, or that are contemplating such action, could view the $80/ton long-term abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of reductions in carbon emissions required to achieve those targets. This is discussed in greater detail in Chapter 6 (Section 6.6.4.2).

The values by year for fuel oil over the study period are presented in Appendix E.

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[119] The full externality value associated with SO_x and NO_x emissions is probably not captured in the allowance price from electricity generation associated with these two pollutants, however determining that externality value is beyond the scope of this project.

[120] EPA. Factsheet: EPA's Final Air Toxics Standard Major and Area Source Boilers and Certain Incinerators Overview of Rules and Impacts. Available at http://www.epa.gov/airquality/combustion/docs/overviewfsfinal.pdf. Accessed June 20, 2011.

Chapter 6: Regional Electric-Energy-Supply Prices Avoided By Energy-Efficiency and Demand-Response Programs

This Chapter projects electricity supply costs that would be avoided by reductions in retail energy and/or demand. Sections 6-1 and 6-2 present the avoided electric capacity and energy supply costs reflected or ‘internalized” in wholesale market prices for electric capacity and electric energy respectively. Sections 6-3 onward presents avoided costs that are not internalized in those market prices, primarily demand-reduction-induced price effects, renewable-energy-credits and externalities.

Capacity Costs: The AESC 2011 projected values of avoided capacity costs are approximately 90 percent higher than those from AESC 2009 on a 15 year levelized basis. The higher values are due to ISO-NE’s decision to extend the price floor through FCA 6 and the projected need for new capacity beyond RPS requirements starting in 2020 driven by: 1) the attribution of 395 MW of passive demand reductions to energy-efficiency measures implemented in 2010 and 2011, 2) regulatory changes that result in certain capacity being treated as out-of-market resources and prohibited from setting the market price, and 3) greater levels of projected retirements of existing capacity.

The AESC 2011 projection of capacity prices is based on the FCA 4 observed supply curve and extrapolations of that curve. This was considered the best approach for AESC 2011 based on the information available and a fair representation of the impacts of projected capacity retirements and additions. That is an area that may warrant further review in future studies.

Wholesale Energy Prices: The AESC 2011 projections of wholesale electric energy costs are approximately 17 percent lower than AESC 2009 on a 15-year levelized basis.[121] This reduction is primarily attributable to a much lower projection of wholesale natural gas costs than in AESC 2009. The remaining portion of the reduction in wholesale energy prices is due to a delay in our assumption of when Federal regulation of carbon emissions would start, from 2013 for AESC 2009 to 2018 for AESC 2011. The reduction of wholesale energy prices in summer peak periods is somewhat less than the reduction in other periods due to the increased in projected retirements of existing capacity, which results in

[121] For comparative purposes, the levelization period for AESC 2009 is 2010-2024 and AESC 2011 is 2012-2026.

less efficient generating units setting market prices in summer peak periods as compared to AESC 2009.

Avoided RPS Costs: AESC 2011 projects lower Class I REC prices through 2024 compared to AESC 2009. These results are driven by a surplus of renewable generation in the near term and projections of lower cost of new entry for renewables. For other renewable tiers, AESC 2011 projects REC prices that generally parallel Class I REC price projections for Class II RECs, or decrease with inflation for other classes. For solar RECs, AESC 2011 projects prices decreasing based on program-specific details.

Capacity DRIPE: The 2011 AESC estimates of capacity DRIPE are approximately 3.7 times greater than those from AESC 2009 on a 15-year levelized basis.[122] This increase is primarily due to the projection of higher wholesale capacity prices than in AESC 2009 as well as to the projection of a longer phase-out of capacity DRIPE effects than in AESC 2009. The AESC 2011 projections assume the phase-out or dissipation of capacity DRIPE will last up to 11 years versus four years assumed in AESC 2009. The longer projected dissipation of capacity DRIPE is based upon a detailed analysis of the various factors that tend to offset the reduction in capacity prices discussed in this chapter. Those factors include: 1) timing of new capacity additions, 2) timing of retirements of existing capacity, 3) elasticity of customer demand and 4) the portion of capacity that LSEs acquire from the FCM.

Energy DRIPE: The AESC 2011 estimates of total energy DRIPE are approximately 43 percent higher those from AESC 2009. These higher estimates are primarily due to the projection of lower wholesale energy prices than in AESC 2009. The AESC 2011 projection of an 11 year phase-out for energy DRIPE and 12 year phase-out for capacity DRIPE are within the 7 to 12 year range of other public estimates of DRIPE reviewed for AESC 2011.

Externalities: AESC 2011 uses an estimate of $80/short ton for the long-term marginal abatement cost for carbon dioxide, essentially the same as in AESC 2009. That estimate is based on the cost of limiting CO_2 emissions to a "sustainability target" level, the same approach used for AESC 2009.

[122] AESC 2009 values for 2010 Installations levelized from 2010-2024.

6.1. Forward-Capacity Auction (FCA) Prices Assuming No New Demand-Side Management

The general methodology and basic assumptions underlying our forecast of Forward Capacity Auction (FCA) prices are described in Chapter 2. This section presents additional detailed assumptions that were not presented in Chapter 2 as well as the projections based upon those assumptions.

The AESC 2011 projections of FCA prices effectively begin with FCA 7. The prices in FCA 1 through FCA 4 have already been established. The prices in FCA 5 and FCA 6 will be established in June 2011 and April 2012, however the results of FCA 4 indicate a level of surplus capacity available so large as to keep the capacity price at the floor price through FCA 6, when the floor price expires under the current ISO market rules.

The forecast of FCA prices is developed in three steps

- Forecast physical capacity requirements to be acquired in each FCA
- Forecast physical supply available to bid in each FCA
- Forecast market-clearing price in each FCA

6.1.1. Forecast Physical Capacity Requirements in each FCA

The first step in the forecast of each FCA price is to forecast the physical capacity requirements to be acquired in each FCA, which is referred to as the net installed capacity requirement (NICR). This requirement is net of the Hydro-Quebec Interconnection Capability Credit (HQ ICC) to the utilities, which has varied from 911 MW in FCA 2 to 954 MW in FCA 5. NICR is used in the FCAs, but load-serving entities need to provide capacity totaling their load share of installed capacity requirement (ICR).

- For FCA 6 through FCA 10 we forecast the NICR by multiplying the NICR in the ISO-NE 2010 Regional Supply Plan (RSP) times the ratio of the expected peak forecast in the 2011 CELT divided by the expected peak forecast in the 2010 RSP.[123]
- Beyond FCA 10, we escalate both load and NICR at the average growth rate of the last five years, FCA 6 through FCA 10.

The inputs and results are presented in Exhibit 6-1 shown below.

[123] The FCA5 NICR is based on the ISO's March 8, 2011, filing with FERC for the FCA5 ICR values.

Exhibit 6-1: Extrapolation of Net Installed Capacity Requirement

		RSP 2010		CELT 2011			
	Year starting	**Expected Peak**	**NICR**	**Expected Peak**	**Adjusted NICR**	**NICR Reserve Margin**	**ICR Reserve Margin**
		a	B	C	d	e	f
FCA 1	2010	27,190	31,110			14.4%	19.6%
FCA 2	2011	27,660	32,528			17.6%	20.9%
FCA 3	2012	28,165	31,965			13.4%	16.6%
FCA 4	2013	28,570	32,127			12.5%	15.7%
FCA 5	2014	29,025	32,610			12.4%	15.7%
FCA 6	2015	29,450	33,178	29,380	33,099	12.7%	15.9%
FCA 7	2016	29,785	33,604	29,775	33,593	12.8%	16.0%
FCA 8	2017	30,110	34,025	30,155	34,076	13.0%	16.2%
FCA 9	2018	30,430	34,434	30,525	34,542	13.2%	16.3%
FCA 10	2019	30,730	34,818	30,875	34,982	13.3%	16.4%
FCA 11	2020			31,260	35,470	13.5%	16.5%
FCA 12	2021			31,651	35,964	13.6%	16.6%
FCA 13	2022			32,046	36,465	13.8%	16.8%
FCA 14	2023			32,446	36,973	14.0%	16.9%
FCA 15	2024			32,851	37,488	14.1%	17.0%
FCA 16	2025			33,261	38,010	14.3%	17.1%
FCA 17	2026			33,677	38,539	14.4%	17.3%
Notes:							
a.	2010 Regional System Plan, Table 4-1.						
b.	2010 Regional System Plan, Table 4-1, except FCA 2, 3, and 5 from "Summary of ICR, LSR & MCL for FCM and the Transition Period," ISO-NE, March 26, 2011. All values are based on 2010 forecast, expect FCA 1, based on 2009 forecast.						
c.	FCA 11 to FCA 17 extrapolated at growth rate FCA 6 to FCA 10.						
d.	(b÷a) × c; FCA 11 to FCA 17 extrapolated at growth rate FCA 6 to FCA 10.						
e.	FCA1 to FCA 5: b÷a – 1; FCA 6 on: d÷c – 1						
f.	e + HQ ICC÷a; HQ ICC = 1,400 MW in FCA 1, 911–916 MW in FCA 2 to 4, 954 MW in FCA 5						
Values in shaded cells have been set by ISO-NE.							

6.1.2. Forecast Physical Supply Available to Bid in each FCA

To estimate the quantity of capacity that would potentially be available to bid into FCA 5 and beyond, we begin with the 36,663 MW that cleared in FCA 4.[124] We make several adjustments to that capacity as shown in Exhibit 6-2 below.

[124] This value does not include 88 MW of real-time emergency generation in excess of the 600 MW that the ISO counts toward the NICR, or the 838 MW of Maine capacity and New Brunswick imports in excess of the capacity in Maine that the ISO counts towards the NICR.

- Remove the energy efficiency resources that cleared in FCA 4, but not in FCA 1, and were thus added after 2010, and should not be included in our Reference Case;
- Subtract capacity that our Reference Case assumes will retire during our study time horizon, as described in Chapter 2;
- Add estimated capacity from projected new renewables post FCA 4; and
- Adjust for the amount of capacity locked up in Maine.

We estimate the capacity reductions from new energy efficiency resources added after 2010 by subtracting the EE resources that cleared in FCA 1 from those that cleared in FCA 4. The on-peak and seasonal resources (i.e., passive demand resources, which are almost all energy-efficiency programs) that cleared in FCA 1 totaled 581 MW, including a 14.3% credit for avoided reserves. The reserve credit was eliminated in FCA 3, so the resources cleared in FCA 1 contributed 508 MW in FCA 3 and FCA 4 (581 ÷ 1.143 = 508). In FCA 4, a total of 1,298 MW of on-peak and seasonal resources cleared, so that auction cleared 790 MW that were not in FCA 1 (1,298 – 508 = 790). We attribute 50% of that 790 MW, 395 MW, to measures installed in 2010 that PAs, to be conservative bid into later auctions.

In this analysis, we assume that the FCM qualifying capacity from the renewables, on average, is equal to the average hourly energy production of the resources. The ratio would be somewhat higher for non-intermittent resources (e.g., biomass), and somewhat lower for much on-shore wind. The following exhibit summarizes our analysis of new renewables and retirements.

Exhibit 6-2: FCM Effects of New Renewables and Retirements

	Year Starting June	New Renewables in New England: Total GWh	Total FCM MW	Post-FCA 4 MW (cumulative)	Retirements: Old Peakers (MW)	Large Units MW	Large Units Units	Total Suppy Effect (MW) (Cumulative)
		[1]	[2]	[3]	[4]	[5]		[6]
FCA3	2012	5,921	676			600	Vermont Yankee	-600
FCA4	2013	6,464	738					-600
FCA5	2014	9,279	1,059	321	10	330	Norwalk Harbor	-619
FCA6	2015	11,343	1,295	557	10	607	Salem 3&4, Cleary 8	-1,000
FCA7	2016	12,526	1,430	692	10	807	Middletown 4, Montville 6	-1,682
FCA8	2017	13,303	1,519	781	10			-1,603
FCA9	2018	13,376	1,527	789	10	103	Wyman 1&2	-1,708
FCA10	2019	14,840	1,694	956	10			-1,551
FCA11	2020	15,523	1,772	1,034	10	143	Mt. Tom	-1,626
FCA12	2021	16,605	1,896	1,158	10			-1,512
FCA13	2022	17,315	1,977	1,239	10			-1,441
FCA14	2023	18,280	2,087	1,349	10			-1,341
FCA15	2024	18,982	2,167	1,429	10			-1,271
FCA16	2025	20,126	2,298	1,560	10			-1,150
FCA17	2026	20,649	2,357	1,619	10			-1,101
Notes:								
1	Summary_of_New_RE_Supply-Demand_AESC_2011_041811.xlsx, total minus imports							
2	[1] ÷ 8.76; assumes capacity value equals average output							
3	[2] – [2] for FCA 4							
4, 5	See Section 2.3.2.5.							
6	[3] – sum([[4] + [5]) for 2012 to current year							

The Maine adjustment shown in Exhibit 6-3reflects the fact that not all capacity in Maine is able to contribute to meeting regional reliability requirements. The ISO sets a Maximum Capacity Limit (MCL) for Maine, roughly equal to the sum of Maine's load and the transfer capability from Maine to New Hampshire.[125] In FCA 4, 838 MW of capacity in Maine could not be applied to meeting the regional capacity requirement. We assume that the locked-in capacity in Maine increases as

[125] The MCL is derived from a complex and poorly-documented reliability analysis, but the MCL has been quite close to the sum of Maine load and the Maine-New Hampshire transfer capability.

transfer capability declines and as capacity is added in Maine, and decreases as Maine load grows, using more of the Maine capacity locally.[126]

In 2014, we assume that the Maine Power Reliability Program (MPRP) will increase transmission capacity from Maine to New Hampshire. ISO-NE has not yet estimated the effect of the project on the Maine-New Hampshire transfer limit, and it also appears that relaxing that constraint may well create a new constraint at the NH export boundary. We assume that the net effect is that the MCL is increased by 500 MW, offset by a 25 MW decrease that ISO-NE expects in 2015.

Exhibit 6-3: FCM Effect of Maine Maximum Capacity Limit

	Starting June	Transmission Capacity Effect	Increased Maine Renewables	ME Expected Load	ME load growth	Net ME Locked-in MW
		[1]	[2]	[3]	[4]	[5]
FCA4	2013			2,115		
FCA5	2014	-500	120	2,150	-35	85
FCA6	2015	-475	172	2,180	-65	-368
FCA7	2016	-475	201	2,210	-95	-369
FCA8	2017	-475	175	2,240	-125	-425
FCA9	2018	-475	175	2,275	-160	-563
FCA10	2019	-475	406	2,300	-185	-357
FCA11	2020	-475	406	2,330	-215	-387
FCA12	2021	-475	199	2,361	-246	-625
FCA13	2022	-475	199	2,392	-277	-657
FCA14	2023	-475	199	2,424	-309	-688
FCA15	2024	-475	199	2,457	-342	-720
FCA16	2025	-475	199	2,489	-374	-753
FCA17	2026	-475	199	2,522	-407	-786
Notes:						
1	Exhibit 2-7					
2	SEA Forecast					
3	RSP11 ISO-NE, States, & Subarea Forecast Energy & Seasonal Peaks					
4	2,115 – [3]					
5	[1] + [2] + [3]; from FCA 9 on, -103 MW for retirement of Wyman 1 & 2.					

[126] The FCM price set for generation in Maine has been lower than the rate for the rest of the pool in most of the FCAs, but the price charged to load has been the same in throughout New England

The resulting estimates of supply and annual surplus (shortages) are summarized in Exhibit 6-4

Exhibit 6-4: Modeled FCM Capacity Surplus

	Starting June	Total Suppy Effect (MW)	Net ME Locked-in MW	Net Change from FCA 4 (MW)	Total Resources at FCA 4 Floor Price	NICR (MW)	Surplus (Shortage) at FCA 4 Floor Price
		[1]	[2]	[3]	[4]	[5]	[6]
FCA3	2012	-600			35,668	31,927	3,741
FCA4	2013	-600			35,668	32,127	3,541
FCA5	2014	-619	85	-704	35,564	33,200	2,364
FCA6	2015	-1,000	-368	-617	35,636	33,099	2,537
FCA7	2016	-1,682	-369	-1,292	34,956	33,593	1,363
FCA8	2017	-1,603	-425	-1,159	35,089	34,076	1,013
FCA9	2018	-1,708	-563	-1,233	35,123	34,542	581
FCA10	2019	-1,551	-357	-1,277	35,074	34,982	92
FCA11	2020	-1,626	-387	-1,317	35,029	35,470	-441
FCA12	2021	-1,512	-625	-971	35,381	35,964	-583
FCA13	2022	-1,441	-657	-870	35,483	36,465	-982
FCA14	2023	-1,341	-688	-737	35,615	36,973	-1,358
FCA15	2024	-1,271	-720	-633	35,717	37,488	-1,771
FCA16	2025	-1,150	-753	-479	35,871	38,010	-2,139
FCA17	2026	-1,101	-786	-395	35,953	38,539	-2,586
Notes:							
1	Exhibit 6-2						
2	Exhibit 6-3						
3	[1] – [2]						
4	36,663 cleared – 395 MW passive DR + [3]; FCA 3 and FCA 4 adjusted for retirement of Vermont Yankee						
5	Exhibit 6-1						
6	[4] – [5]						

6.1.3. Forecast Market-Clearing Price in Each FCA

The third step in the forecast of each FCA price is to forecast the price at which the FCA would clear, i.e., the intersection of demand curve and the supply curve.

Our Reference Case projects that FCA 5 and FCA 6 will clear at the floor price because of the surplus capacity indicated by FCA 4. FCA 4 ended with 36,663 MW of capacity clearing at the floor price, excluding excess Maine generation and real-time emergency generation. This represents an excess of 4,536 MW relative to the NICR.

The 4,536 MW excess included 1,527 of capacity that the ISO considered to be out-of-market capacity (OOM), i.e., capacity that the ISO found could not be supported by market revenues, and which were not allowed to set the market price in FCA 4. Of that 1,527 MW, approximately 1,227 MW are resources that FERC has grandfathered from the effects of OOM treatment in an April 2011 Order; the remaining 300 MW were new demand-response and generation resources in FCA 4 that FERC did not explicitly grandfather in that order, and thus may not be able to affect the market price.[127]. The 36,663 MW also includes about 395 MW of post-2010 energy-efficiency excluded from our analysis.[128]

There would still be an excess of 3,841 MW after excluding the 395MW from 2010 energy efficiency measures and the 300 MW of OOM capacity. That excess cleared at $2.95/kW-month (or about $2.84/kW-month in 2011 dollars). That surplus is large enough to keep the capacity price at the floor price through FCA 6, when the floor price expires under the current ISO market rules.

We forecast the prices in FCA 7 and beyond based upon the forecast annual requirements, forecast potential supply, the relationship between supply and prices bid in FCA 4, i.e. the FCA 4 observed supply or bid curve, and extrapolations of the FCA 4 supply curve. As capacity is retired and the NICR rises, we assume that the market-clearing price follows the FCA 4 bid curve. Exhibit 6-5 indicates that the FCA 4 bid curve is comparable to the FCA 3 bid curve. The FCA 3 and FCA 4 bid curves each ended at their floor price.[129]

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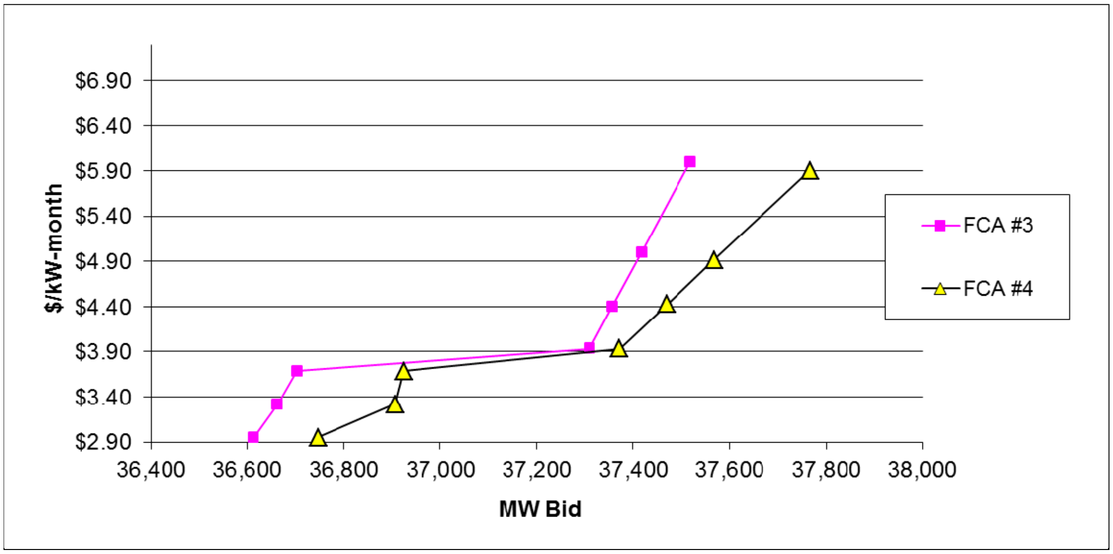
[127] FERC. Docket Nos. ER10-787-000 et al,, Order on Paper Hearing and Order on Rehearing (April 13, 2011). The ISO may remove the OOM designation from some of these resources following further information exchanges with the developers. Future resources may also be classified as OOM. If the OOM capacity does not rise much above the 300 MW level, the OOM designation is not likely to significantly affect future FCM prices.

[128] Some of the efficiency resources were classified as OOM, so these categories overlap.

[129] The shift to the right from FCA 3 to FCA 4 is less than the amount of new energy-efficiency resources that qualified in FCA 4.

Exhibit 6-5: Supply Curves in FCA 3 and 4



Below $2.90 per kw-month, the bottom of the observed supply curve, we assume that prices will continue to fall at the average slope of the FCA 4 curve from $3.90 to $2.90/kW-month, or about $0.0016/kW-month per MW of surplus. The slope of this section of the supply curve is about 2.7 times as steep as the $0.00057/kW-month per MW assumed for excess in AESC 2009. For a given amount of surplus, this assumed supply curve produces lower prices than the supply curve used in AESC 2009.

Above $5.90 per kw-month, the top of the observed supply curve, we assume that the price gradually rises to the costs of adding new generic units at a cost in the $7–$8/kW-month range, referred to as the cost of new entry (CONE). Initial estimates of CONE prepared in 2004 were $7.50/kW-month in 2010[130]. Since those analyses were prepared, costs of equipment have risen and fallen, and lenders have become more risk averse; the cost of new entry remains variable and uncertain.[131] Our specific supply-curve assumptions regarding changes in FCA prices at various increments of supply is shown in Exhibit 6-6.

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[130] See ISO-NE filing in Docket No. ER03-563-030, August 31, 2004.

[131] The costs also vary widely among locations. For example, the bids in the Connecticut peaker procurement (DPUC Docket 08-01-01 were mostly based on capital costs in the range of $1,000–$1,200/kW, but GenOn has proposed two peakers at the Canal plant for about $700/kW (Massachusetts EFSB 10-2, Testimony of Shawn Konary).

Exhibit 6-6: Assumed FCM Supply Curve, 2011 dollars

MW Required relative to the Capacity Cleared in FCA 4	Declining 20%	
	Incremental slope of FCA price	Total FCA price
	$/kW-month per MW	$/kW-month
-1000	$0.0016	$1.26
-800	$0.0016	$1.58
-600	$0.0016	$1.89
-400	$0.0016	$2.21
-200	$0.0016	$2.52
0		$2.84
200	$0.0040	$3.64
400	$0.0005	$3.74
600	$0.0005	$3.84
800	$0.0050	$4.84
1000	$0.0050	$5.84
1200	$0.0035	$6.54
1400	$0.0025	$7.03
1600	$0.0017	$7.37
1800	$0.0012	$7.61
2000	$0.0008	$7.78
2200	$0.0006	$7.90
2400	$0.0004	$7.98
2600	$0.0003	$8.04
FCA Price = Previous price + slope × capacity increment (200 MW)		

Our Reference Case assumes that the 300 MW of OOM capacity would be excluded from the computation of the market-clearing price in FCA 7 through FCA 10 because of the FERC order note earlier. Based on that assumption and our assumed supply curve, the FCM price would fall to about $1.16 in FCA 7. It would then start rising gradually through a transition period to FCA 12 by which time all existing surplus capacity is utilized. During this transition capacity prices are set by resources that did not clear in FCA 4, including at least the following:

- Demand response and incremental capacity at existing units that cleared at higher prices in FCA 1 and FCA 2, but withdrew by FCA 4;
- New demand response;
- Upgrades at existing units;
- Combined heat and power;
- Imports;
- Reactivated generation; and

- Possibly new generation units with highly favorable conditions (e.g., transmission or distribution relief, existing sites, municipal financing).

Some of those resources may be defined as new under the FCA rules, allowing some of the OOM capacity to be treated as normal capacity in each subsequent auction.

By FCA 12, the OOM capacity would all be utilized and more expensive resources would clear, resulting in a rapid rise in FCM price. For the purposes of this analysis, we have assumed 80% of OOM capacity will be treated this way.

The resulting forward capacity prices for the Reference Case are shown in Exhibit 6-7.

Exhibit 6-7: FCM Price Projection, Reference Case, AESC 2011 and AESC 2009 (2011 dollars)

	Year start	Excess including all OOM Capacity	Net of OOM	AESC 2011 FCA Price 2011$ $/kW-month	AESC 2009 FCA Price (2011$/kW-month)
FCA 1	2010				$4.46
FCA 2	2011				$3.49
FCA 3	2012			$2.89	$2.81
FCA 4	2013			$2.84	$1.32
FCA 5	2014	2,364		$2.84	$1.32
FCA 6	2015	2,537		$2.84	$1.43
FCA 7	2016	1,363	1,064	$1.16	$1.53
FCA 8	2017	1,013	714	$1.71	$1.53
FCA 9	2018	581	282	$2.39	$1.63
FCA 10	2019	92	0	$2.68	$1.63
FCA 11	2020	-441		$3.76	$1.73
FCA 12	2021	-583		$3.83	$1.83
FCA 13	2022	-982		$5.75	$1.94
FCA 14	2023	-1,358		$6.92	$2.04
FCA 15	2024	-1,771		$7.57	$2.14
FCA 16	2025	-2,139		$7.86	
FCA 17	2026	-2,586		$8.03	
15 year Levelized				**$4.01**	**$2.10**
Notes: Excess from Exhibit 6-4.					

6.1.3.1. Comparison to AESC 2009

AS shown in Exhibit 6-7, other than in FCA 7, these values are considerably higher than the AESC 2009 projections, due to the following factors (in addition to various changes in NICR and resources bid into the latest FCA):

- The extension of the price floor through FCA 6,
- The assumption that larger amounts of capacity will retire in the next few years. In AESC 2009, we did not anticipate the retirement of the generation in Exhibit 6-2, other than Salem, or the 150 MW of other generation that delisted in FCA 4. The AESC 2009 analysis did not explicitly distinguish environmentally-driven retirements from resources that might simply offer capacity at prices above the clearing price in future auctions.
- The elimination of capacity from new energy-efficiency resources from the resources that cleared in the FCAs. The AESC 2009 analysis did not make a comparable adjustment
- The treatment of capacity trapped in Maine. The AESC 2009 analysis did not recognize that incremental capacity in Maine was not able to reduce the market-clearing price.
- The recognition that 300 MW of previously cleared resources may be treated as OOM resources and not allowed to set market prices in future auctions.

6.1.4. Avoided Capacity Costs per MW Reduction in Peak Demand

As described in Chapter 8, a kilowatt reduction from an energy-efficiency measure in a given year can avoid wholesale capacity costs through two broad categories of approaches, i.e., bidding in to FCAs as a resource or reducing the ISO-NE forecast of peak load for which capacity has to be acquired.

If the kilowatt reduction from an energy-efficiency measure in a given year is bid into FCA for that year, its avoided capacity cost is the FCA price for that year and adjusted for an ISO-NE loss factor of 8 percent.

If the load reduction from an energy-efficiency measure in a given year reduces the peak load that ISO-NE forecasts to be served in that year, its avoided capacity cost is the FCA price for that year adjusted upward by the reserve margin ISO-NE requires for that year.

The reserve margin is the ratio of the Net Installed Capacity Requirement (NICR) to forecast peak load that ISO-NE sets each year. The ISO has set NICRs through FCA 5, and has projected NICRs through FCA 10 in RSP 2010. For FCA 1 to FCA 5, Exhibit 6-1 provides the computation of the required reserve margin indicated by the latest determination of NICR for each capacity year.[132] For FCA 6

[132] The reserve margins for FCA 1 to FCA 3 are from reconfiguration auctions, which appear to have little effect on total cost to load (and hence are not used in the rest of this analysis), but indicate the ISO's most recent view of capacity needs.

to FCA 10, the reserve margin is the value reported in the 2010 RSP. Beyond FCA 10, we escalate both load and NICR at the average growth rate in the last five years of the ISO forecast.

The resulting reserve margins are applied to the FCA prices to calculate the avoided capacity cost to load each year, and are presented in the last column of Exhibit 6-8. The forecast of avoided unit capacity cost to load does not reflect any adjustment for marginal losses on the pool transmission facilities of 1.9% and the applicable wholesale risk premium of 9%.

Exhibit 6-8: Forecast of Avoided Unit Capacity Costs

		FCA Prices 2011$				
		$kW-month	$kW-year	Required Reserve	FCA Prices Adjusted for Reserve Margin ($/kW-yr)	Avoided Capacity Cost to Load ($kW-yr)
		a	b	c	d	e
6/1/2011	FCA 2	$3.60	$43.20	21.0%	$52.26	$58.05
6/1/2012	FCA 3	$2.89	$34.72	16.6%	$40.48	$44.96
6/1/2013	FCA 4	$2.84	$34.04	15.7%	$39.37	$43.72
6/1/2014	FCA 5	$2.84	$34.04	17.7%	$40.05	$44.49
6/1/2015	FCA 6	$2.84	$34.04	15.9%	$39.45	$43.82
6/1/2016	FCA 7	$1.16	$13.98	16.0%	$16.22	$18.01
6/1/2017	FCA 8	$1.71	$20.56	16.2%	$23.89	$26.54
6/1/2018	FCA 9	$2.39	$28.72	16.3%	$33.39	$37.09
6/1/2019	FCA 10	$2.68	$32.22	16.4%	$37.50	$41.66
6/1/2020	FCA 11	$3.76	$45.08	16.5%	$52.53	$58.34
6/1/2021	FCA 12	$3.83	$45.94	16.6%	$53.58	$59.51
6/1/2022	FCA 13	$5.75	$68.95	16.8%	$80.51	$89.42
6/1/2023	FCA 14	$6.92	$83.08	16.9%	$97.11	$107.86
6/1/2024	FCA 15	$7.57	$90.89	17.0%	$106.36	$118.14
6/1/2025	FCA 16	$7.86	$94.32	17.1%	$110.49	$122.72
6/1/2026	FCA 17	$8.03	$96.38	17.3%	$113.02	$125.53

Notes:

a	From Exhibit 6-7
b	a*12
c	From Exhibit 6-1
d	b*(1+c)
e	d*(1+1.9%)*(1+WRP of 9%)

The benefit to consumers depends on four factors:

- The percentage of the projected load reduction bid into and cleared in each FCA.

- The timing of reduction in participants' ISO load tags, their share of the NICR.
- The speed with which the ISO recognizes the reduction in load due to energy-efficiency load reductions not bid into the FCAs, reducing the NICR.
- Whether the avoided cost is computed from the perspective of a particular consumer group (a utility's ratepayers, or a state's power consumers) or for all New England load. If the analysis includes DRIPE for the entire region, the avoided capacity cost would logically include only reduction in the regional total FCM charges. Once the NICR is set, load reductions only reduce that regional FCM bill by the amount of FCM revenues to the program administrators. On the other hand, if the analysis includes DRIPE benefits only for one state's consumers, it should logically include the benefits to that group from reducing their share of the FCM bill.[133]

Appendix B includes avoided capacity costs, assuming that consumers start to receive all the benefits from load reductions in the year of installation. If a regulator prefers to assume that some of the benefits will be lagged, the user may delay a portion of the avoided capacity costs.

6.2. Avoided Electric Energy Costs

6.2.1. Forecast of Energy Prices Assuming No New DSM

The projected wholesale energy prices (Reference Case) presented below are outputs from the Market Analytics simulation model for a hypothetical future in which no new energy efficiency resources are implemented after 2010. As such, they represent the wholesale price of avoided energy in a future with no new efficiency. These prices are NOT meant to be used as projections of energy prices in the most likely future, i.e., one in which there will be some level of new energy efficiency measures installed each year over the planning horizon.

Chapter 2 describes the Market Analytics model and the major input assumptions underlying these projections. In addition, that chapter discusses the structure of the electric energy market, and the model and inputs we use to represent the electric energy market for AESC 2011. These key inputs are:

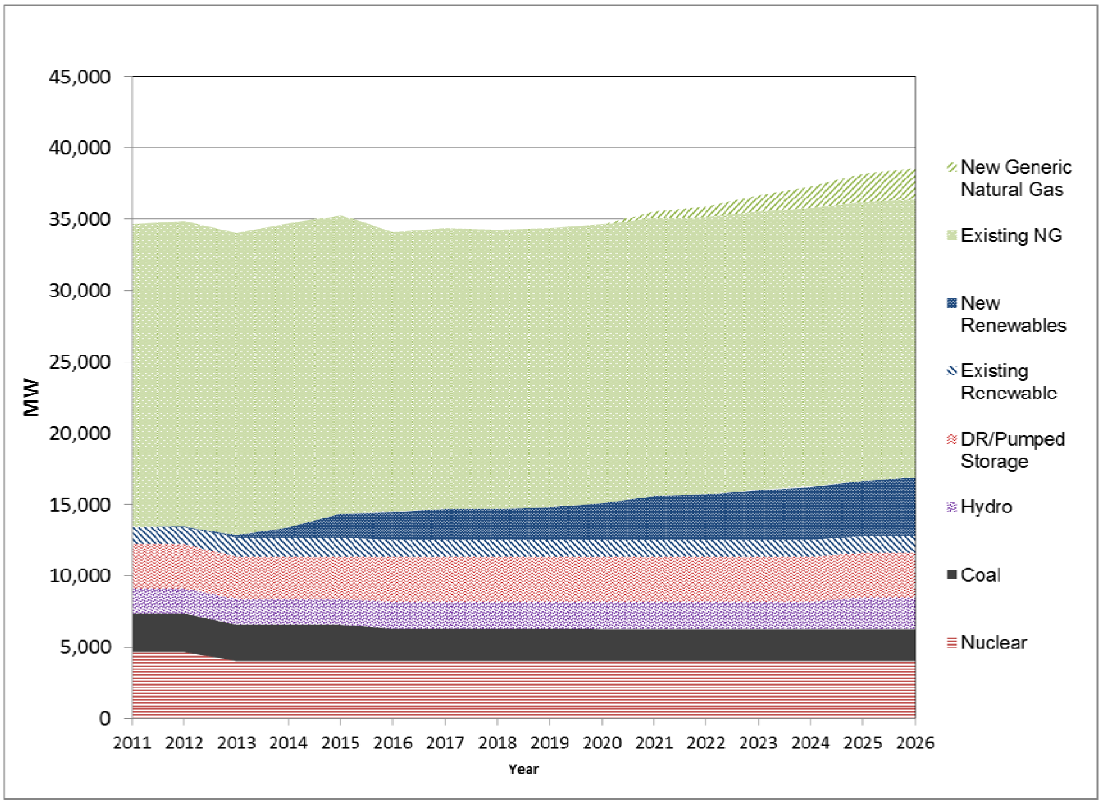
- Projected loads–derived from the latest ISO-NE CELT report;

[133] Various states have treated DRIPE differently: Rhode Island includes regional DRIPE, Massachusetts has included only state DRIPE, and the other states exclude DRIPE. These practices may change over time.

- Projected resources—based on available public information such as the capacity auctions and the current state RPS requirements for renewables
- Forecast prices for natural gas, coal and oil, and
- Forecast emission regulation compliance costs for CO_2, SO_2 and NO_x.

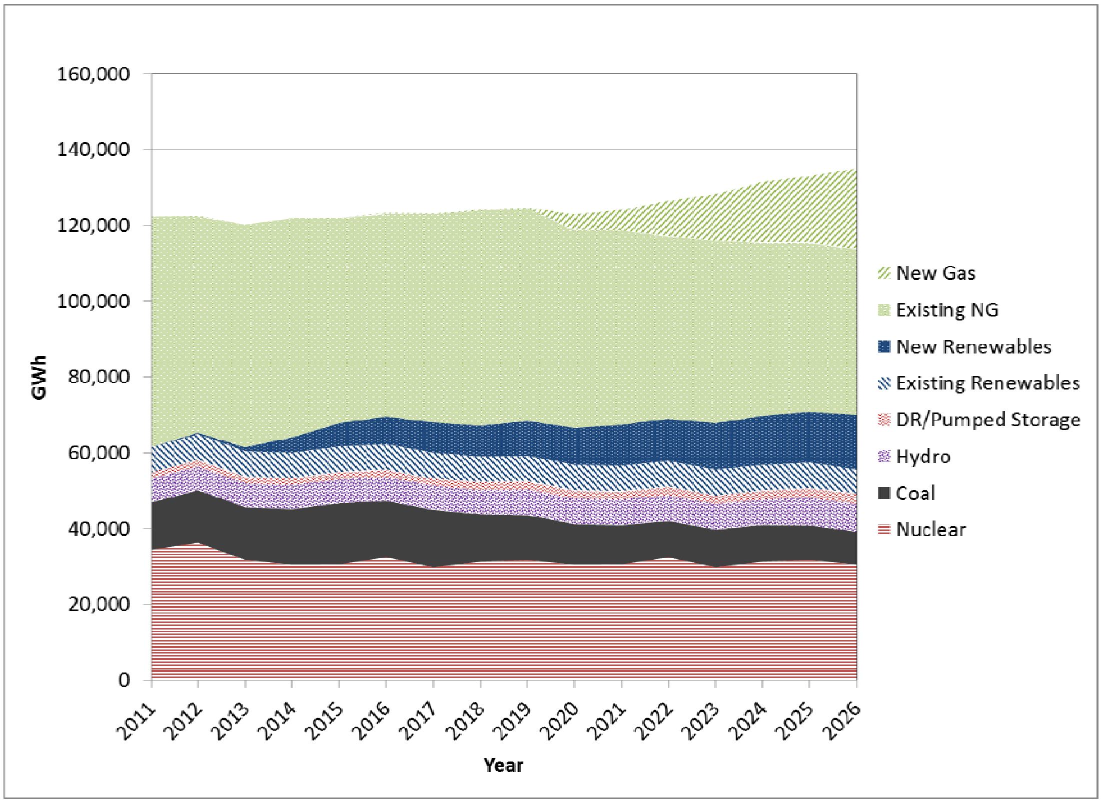
The projected level and mix of capacity in the Reference Case is presented in Exhibit 6-9 below. Most capacity additions are renewable resources, top rows, to comply with RPS requirements, but there are also some new natural gas generators added after 2019. The oil capacity are primarily peakers that get very little use, as shown by their apparent absence in the next graph that shows generation.

Exhibit 6-9: Reference-Case Capacity by Source (MW)



The projected level and mix of generation in the Reference Case is presented in Exhibit 6-10 below. Generation from nuclear declines slightly with the closure of Vermont Yankee in 2014, and coal generation also declines as some older units are retired. Generation from natural gas is the dominant resource declining slightly in the near term but rising a bit in the later years. Renewable generation increases substantially in compliance with RPS requirements.

Exhibit 6-10: Reference-Case Generation by Source (GWh)



The prices projected in the Reference Case are:

- On a levelized (2010-2024 for AESC 2009 versus 2012-2026 for AESC 2011) annual basis 17 percent below those from AESC 2009. The reductions are generally less for summer peak periods and greater for other periods as shown in Exhibit 6-11;[134]
- Within 0.4 percent of NYMEX futures for ISO NE, as of March 18, 2011, for 2011 through 2016.

6.2.1.1. Forecast of Wholesale Electric Energy Prices

For AESC 2011, we present streams of energy values for all of New England in the form of “the hub price.” It requests forecasts for the following four streams—summer on-peak, summer off-peak, winter on-peak, winter off-peak.

The hub price representing the ISO-NE Control Area is located in central Massachusetts and the Central Massachusetts zone in Market Analytics model is used as the proxy for that location. Exhibit 6-11 below presents summer and

[134] All levelized values have been calculated using the AESC 2011 discount rate of 2.46 percent.

winter, on-peak and off-peak energy prices as produced by the model through 2026 for Central Massachusetts.

Exhibit 6-11: Wholesale Energy Price Forecast for Central Massachusetts

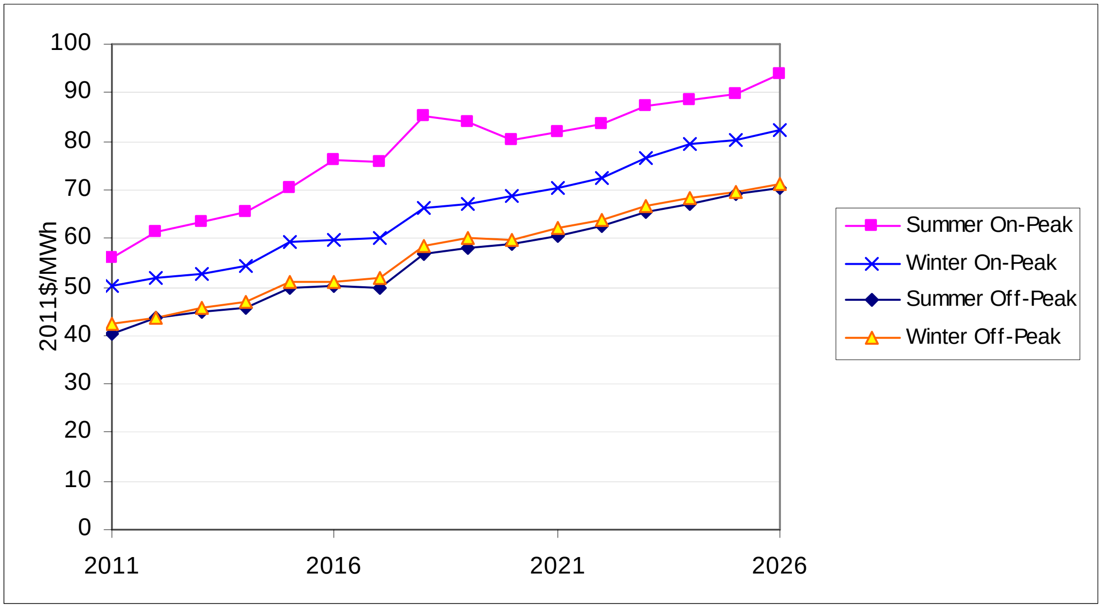


Exhibit 6-12 provides the prices in tabular form.

Exhibit 6-12: Wholesale Energy Price Forecast for Central Massachusetts

Year	Summer Off-Peak	Summer On-Peak	Summer All-Hours	Winter Off-Peak	Winter On-Peak	Winter All-Hours	Annual All-Hours
2011	40.33	55.97	47.77	42.33	50.16	46.05	46.38
2012	43.51	61.52	52.07	43.56	51.69	47.43	48.73
2013	44.94	63.19	53.62	45.53	52.84	49.01	50.27
2014	45.69	65.56	55.14	46.78	54.29	50.36	51.68
2015	49.90	70.34	59.62	50.88	59.46	54.96	56.21
2016	50.41	76.20	62.68	50.85	59.73	55.07	57.33
2017	49.87	75.78	62.19	51.96	60.03	55.80	57.64
2018	56.68	85.36	70.32	58.38	66.11	62.06	64.47
2019	57.83	83.97	70.26	60.08	66.97	63.36	65.29
2020	58.73	80.24	68.96	59.83	68.88	64.14	65.37
2021	60.43	81.81	70.60	62.07	70.51	66.09	67.19
2022	62.41	83.37	72.38	63.81	72.46	67.93	69.00
2023	65.62	87.32	75.94	66.66	76.54	71.36	72.46
2024	67.28	88.67	77.45	68.48	79.22	73.59	74.44
2025	69.32	89.86	79.09	69.38	80.26	74.56	75.61
2026	70.27	93.80	81.46	71.22	82.24	76.46	77.68
Levelized 2012-2026	55.95	78.16	66.51	57.04	65.72	61.17	62.60
All prices expressed in 2011$ per MWh.							

6.2.1.2. Analysis of Forecasts of Wholesale Electric Energy Prices

The scope of work requests the following analyses of the forecast:

- Comparisons with other trends and forecasts, including comparisons to a trend of actual monthly prices (real time) from ISO-NE, a forecast as represented by the NYMEX futures market and the most recent EIA forecast;
- A high level discussion of reasons for differences identified in the comparisons; and
- Explanation of any apparent price spikes and key variables that affect the outcome, as well as identification of potential scenarios worthy of investigation.

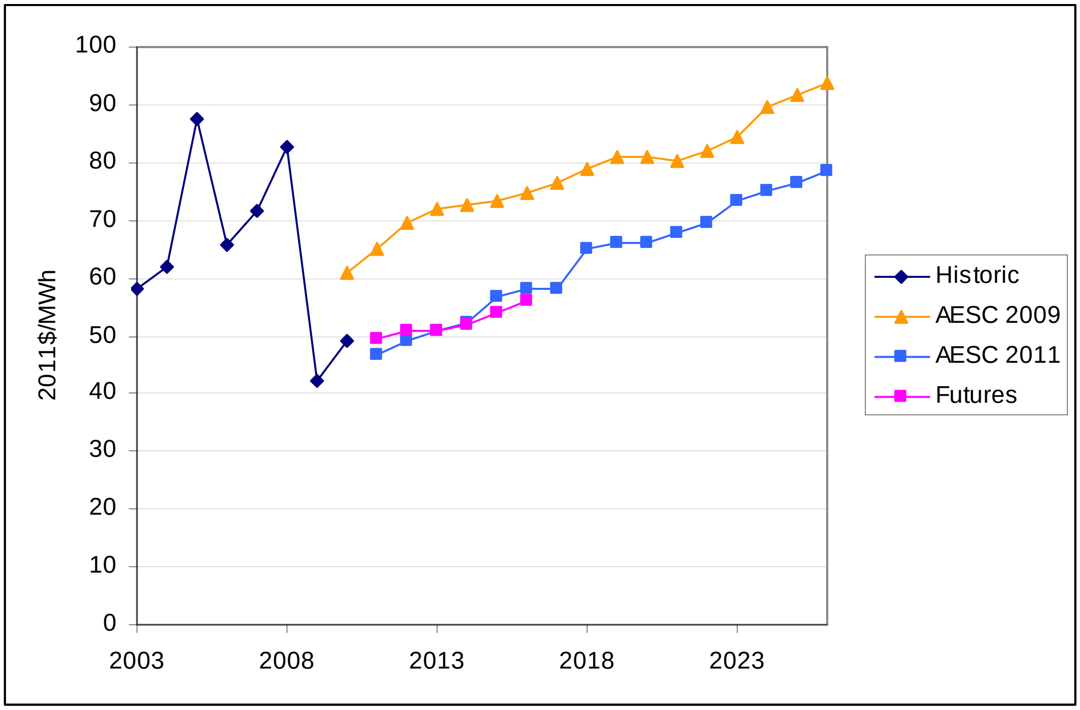
6.2.1.3. Comparison with the AESC 2009 Forecast and Historic Values

Exhibit 6-13 provides a comparison of 1) historical prices, 2) AESC 2009, and 3) AESC 2011 forecasts of the annual wholesale energy prices in the Central Massachusetts zone.

Exhibit 6-13 indicates that the AESC 2011 forecast is significantly below AESC 2009. The lower AESC 2011 forecast reflects significant reductions in the cost of natural gas which is generally the marginal generation fuel. It also reflects somewhat lower annual loads as well as lower CO_2 prices.

The AESC 2011 Reference case forecast of Henry Hub natural gas prices start in 2011 at $4.41/MMBtu, which is about $2.00 below the AESC 2009 forecast. Over time that gap narrows but still remains lower by about $1.00. The irregularities in the annual electricity price curve primarily represent the natural gas price changes, although the 2018 rise is associated with the start of CO_2 emission pricing.

Exhibit 6-13: Historic and Forecast Annual Wholesale Price Comparisons



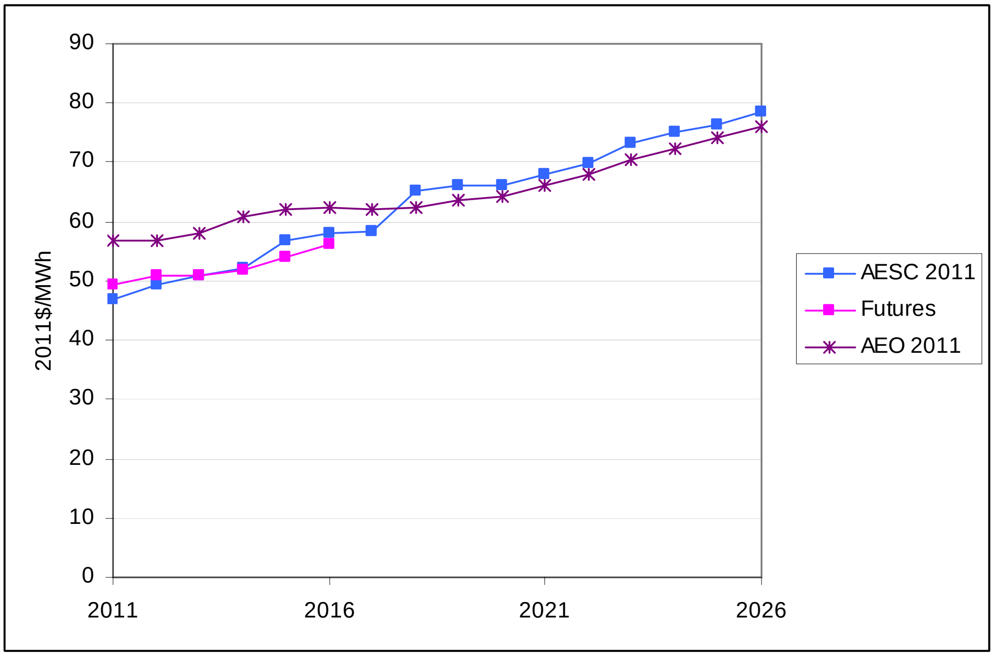
6.2.2. Comparison with Other Forecasts

The following section details comparisons of the AESC 2009 forecast with other forecasts.

6.2.2.1. Comparison with AEO 2011 Forecast

The Annual Energy Outlook is annually released by the EIA and forecasts energy usage and price for the U.S. as a whole and for its constituent regions. Table 77 of the report presents generation, capacity and prices for New England. Although the AEO does not produce a market price per se, the generation service category price comes fairly close. Exhibit 6-14 below compares that generation price with the AESC 2011 forecast.

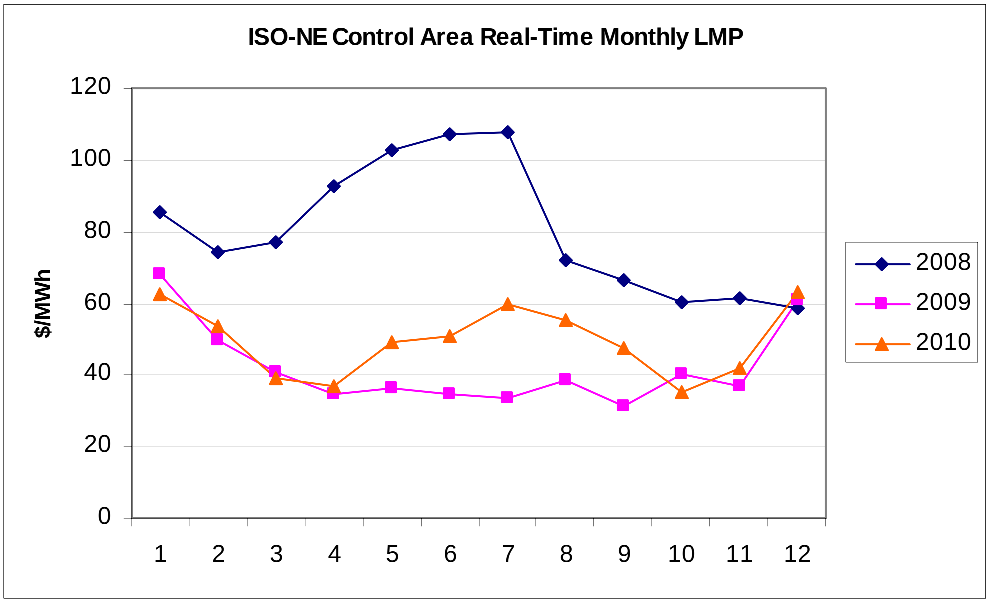
Exhibit 6-14: Forecast Comparison with AEO 2011



6.2.2.2. Comparison with Trends in ISO NE Prices

Variations in historical monthly prices in ISO-NE in 2008, 2009, and 2010 are explained by variation in monthly electricity loads and natural gas prices. Exhibit 6-15 shows the electricity monthly prices in each of the last three calendar years. The general pattern is that high loads in the summer increase prices above the spring and autumn periods. And moderately higher winter loads combined with sometimes much higher spot natural gas prices can result in even higher winter prices. In 2009, a year with generally lower loads, the winter prices were higher than the summer ones. In 2010 with higher loads, the summer and winter prices were similar. In 2008, electricity prices peaked in the summer due to what is now recognized as a natural gas price bubble that collapsed that autumn. As discussed elsewhere the primary driver of electricity prices in New England are the spot natural gas prices which tend to be low in the summer but can spike considerably during cold winter periods. The AESC 2011 forecast of monthly prices is consistent with this historical trend.

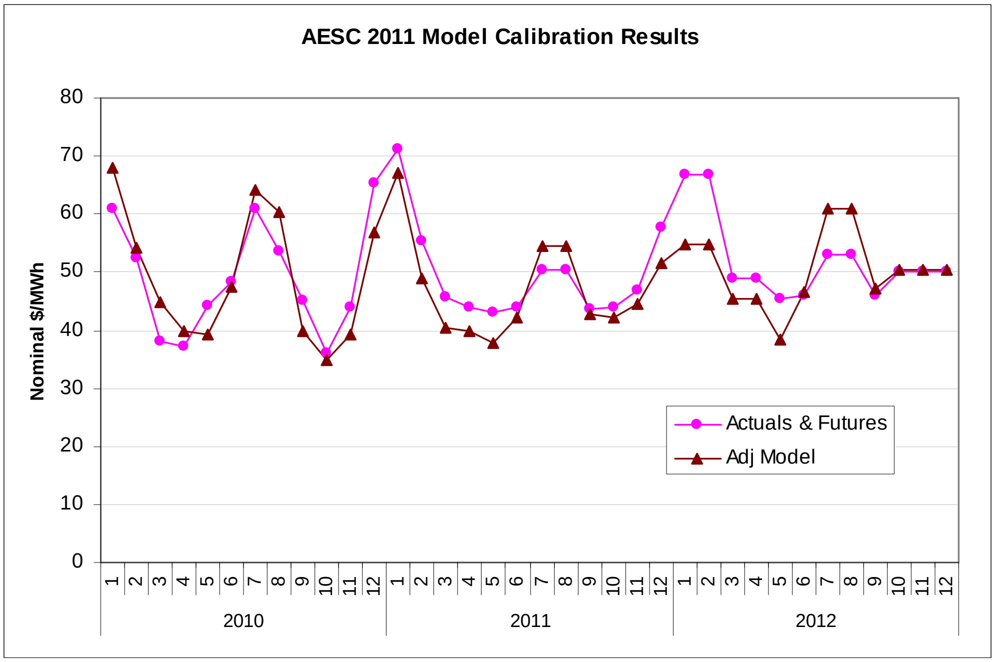
Exhibit 6-15: ISO-NE Control Area Monthly Real-Time Prices



The Chicago Mercantile Exchange (CME) maintains the NYMEX futures market for electricity prices at the New England Hub. There is a moderate amount of trading out about a year or two, but further out the market is quite thin. Nevertheless these futures prices provide one source of comparison with the AESC forecast. For this Study we use futures as of March 18, 2011.

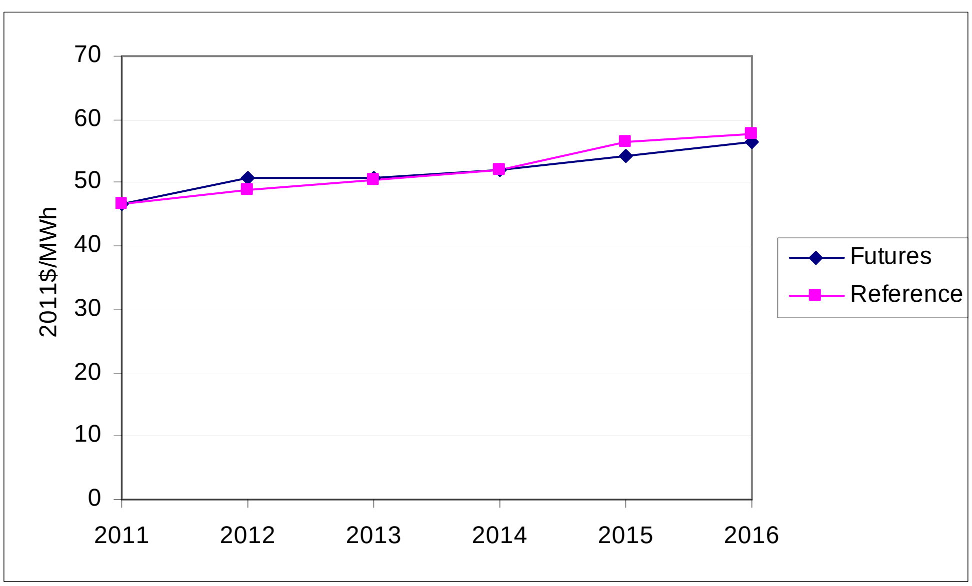
Exhibit 6-16 shows the comparisons on a monthly basis corresponding to the NYMEX products which are often based on multiple months. Considering the volatility of the futures markets the correspondence is amazingly close.

Exhibit 6-16: AESC vs. NYMEX New England Futures



The next Exhibit compares the futures and the AESC forecast energy prices on an annual average basis. The correspondence is extremely close and represents both the assumptions about natural gas prices and the calibration process that we carried out adjusting the model bidding parameters.

Exhibit 6-17: Comparison of Futures and Reference Case Annual Prices



6.2.2.3. Comparison to AESC 2009 Forecast

The following section summarizes forecast differences between AESC 2011 and AESC 2009. Exhibit 6-18 compares the two AESC forecasts on a levelized basis. Differences exist between the two forecasts occur in all years and periods in the order of 8.7 to 20.1 percent.

Exhibit 6-18: 15-Year Levelized Cost Comparison for Central Massachusetts (2011$/MWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual All-Hours Energy
AESC 2011	$65.72	$57.04	$78.16	$55.95	$62.60
AESC 2009	82.35	68.41	85.69	65.49	75.37
% Difference	-20.2%	-16.6%	-8.8%	-14.6%	-16.9%

Notes:
Levelization periods: 2010-2024 for AESC 2009; 2012-2026 for AESC 2011
Discount rate of 2.46%

There are several key factors causing the current forecast to differ from that of AESC 2009:

- Natural gas price – Natural gas prices are the primary determinant of electricity prices in the New England wholesale market. The current natural gas price forecast is significantly (17.4 percent) below the previous one.
- CO_2 price – The current forecast for a national price for CO_2 starts four years later in 2018 and on a levelized basis (2010-2024 for AESC 2009 and 2012-2026 for AESC 2011) AESC 2011 is 31 percent lower than AESC 2009.[135]
- Load Levels – the projections of peak demand used in AESC 2011, which are based on CELT 2011, are about 3 percent below those used in AESC 2009. In projections of annual electric energy used in AESC 2011 are about 3 percent greater than in AESC 2009.

The impact of each of these factors is discussed in more detail below.

[135] On levelized basis for the same period (2012-2026), the difference between AESC 2009 and AESC 2011 is 44 percent.

New England Natural Gas Price Forecast

Prices in the New England electricity energy market have been historically very volatile. This volatility is very strongly linked to the price that electric generators pay for natural gas. The graph below shows these prices on a monthly average basis for the previous five years. One thing to note is that although electricity prices closely follow natural gas prices, they tend to be proportionally higher in the summer when loads are greater.

Exhibit 6-19: Historical New England Electricity and Natural Gas Prices

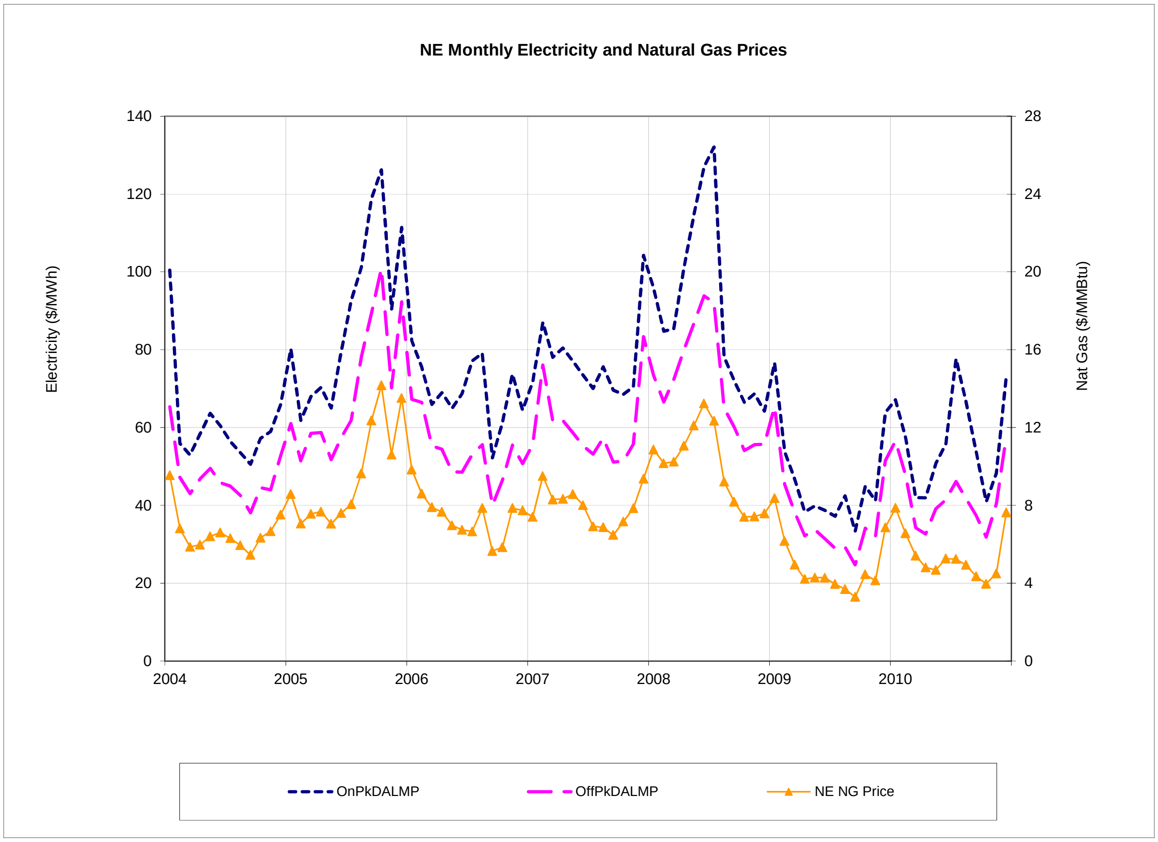
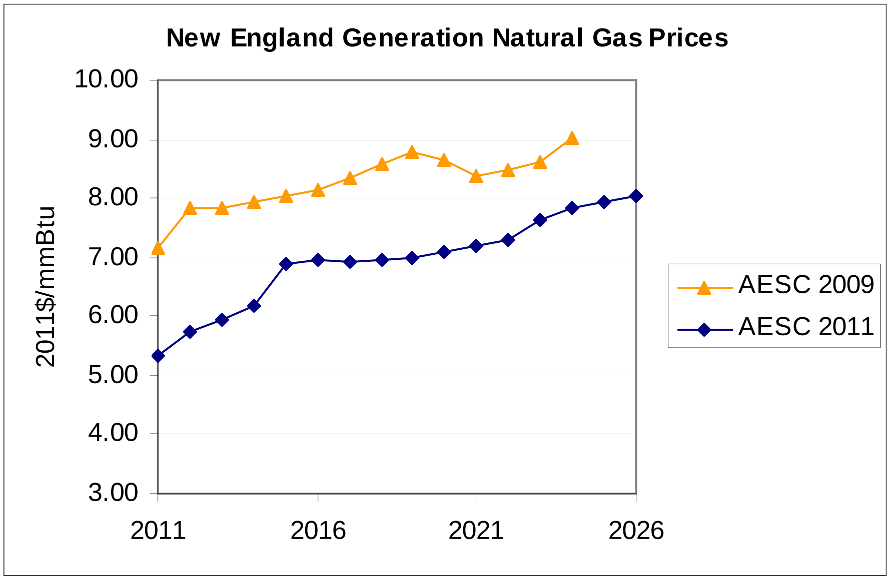


Exhibit 6-20 compares the current natural gas forecast for electric generation in New England which reflects historic margins in the spot market compared to that of AESC 2009. The AESC 2011 forecast has much lower prices in all years. On a levelized basis (2010-2024 for AESC 2009 and 2012-2026 for AESC 2011) the current natural gas price forecast is $1.12/MMBtu or 13.8 percent below AESC 2009.[136]

[136] For the same levelization period (2012-2026), the AESC 2011 New England natural gas forecast is $1.47/MMBtu or 17.4 percent lower than AESC 2009.

Exhibit 6-20: AESC 2011 vs. AESC 2009 Gas Price Forecast Comparison



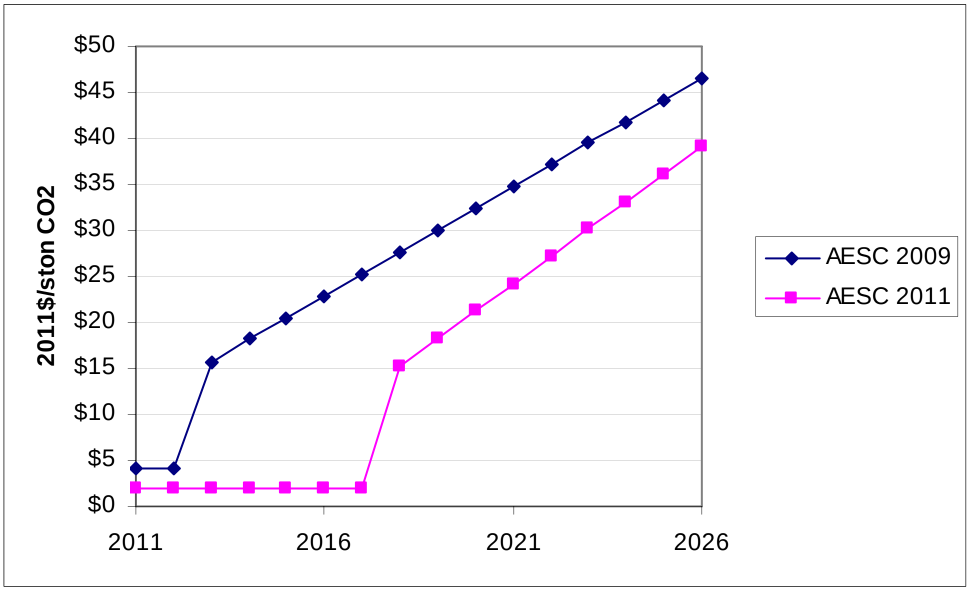
In terms of the seasonal differences the winter (eight month) prices average 3.5 percent above the annual average and the summer (four month) prices average 6.9 percent below. This differs slightly from AESC 2009 where those seasonal differences were +3.2 percent and -6.4 percent respectively.

CO_2 Price Forecast

The CO_2 Price forecast used for AESC 2011 is significantly below that used in AESC 2009 reflecting expectations of significantly delayed national regulation as shown in Exhibit 6-21. The levelized (2012-2026 for AESC 2011 and 2010-2024 for AESC 2009) cost for AESC 2011is $15.69/ton compared to $22.70/ton for AESC 2009, a $7.01 or a 31 percent decrease reflecting primarily the delay from 2014 to 2018.[137] Note too that AESC 2009 had high CO_2 prices starting quite early in 2013, whereas for AESC 2011 high CO_2 prices do not start until 2018.

[137] Over the same levelization period (2012-2026), the difference between AESC 2011 and AESC 2009 is $12.49 or 44 percent.

Exhibit 6-21: AESC 2011 & 2009



Load Forecast

As discussed in Chapter 2, the CELT 2011 loads used for AESC 2011 are very close to those used in 2009. The summer peak loads are about three percent less, but the annual energy loads are about three percent greater. Although load levels have an effect on market prices, these types of changes would have a very minimal effect on the overall energy prices.

Analysis of Forecast Differences

There are many factors that go into the wholesale electricity price that include both fuel and environmental costs and system operation. The following exhibit focuses on a comparative analysis of the summer peak prices for AESC 2009 and AESC 2011. As noted previously the AESC 2011 summer peak price on a levelized basis was 13.2 percent below the previous one. The following exhibit presents an illustrative calculation of those two summer prices and the resulting differences keeping in mind that there are numerous year by year variations.

The table starts by showing the levelized wholesale prices over a comparable period using the same discount rate. That is followed by values for two of the key inputs - natural gas and CO_2 prices. The system parameters represent overall system behavior and are consistent with the behavior we see and expect from the dispatch modeling. A key difference with the current simulation is that there are significantly more retirements of base load resources such as Vermont Yankee and several coal plants. Those retirements shift the generation supply curve to the left which causes less efficient units to set the market price in summer peak periods, when loads are highest, as compared to AESC 2011. The result is that the decrease in summer peak period prices in AESC 2011 relative to AESC 2011 due to lower natural gas and CO_2 prices is offset somewhat by the 9.7 percent lower efficiency of the marginal units in those periods. This is why there is less of a reduction in summer peak period prices under the AESC 2011 forecast compared to AESC 2009 than for other periods of the year during which loads are generally less.

Exhibit 6-22: AESC 2011 vs. AESC 2009 Levelized Cost Comparisons

WCMA Summer On-Peak Period Price Comparison (2011$ per MWh)			
	AESC 2009	**AESC 2011**	**% Difference**
Wholesale Price from Simulation Model	**$85.69**	**$78.16**	**-8.8%**
Analysis			
Input Values			
Summer NG Price ($/MMBtu)	$7.61	$6.49	-14.7%
CO_2 Price ($/ton)	$22.70	$15.69	-30.9%
NG CO_2 (lbs/MMBtu)	118	118	
Marginal Heat Rate (Btu/kWh)	9,250	10,150	9.7%
Marginal CO_2 Rate (tons/MWh)	0.54	0.60	9.7%
Price and Heat Rate Effects			
Fuel Cost ($/MWh)	$70.35	$65.86	-6.4%
CO_2 Cost ($/MWh)	$12.39	$ 9.40	-24.2%
Other variable & bid costs ($/MWh)	$ 3.00	$ 3.00	0.0%
Wholesale Price Estimated from Price and Heat Rate effects + other variable costs	**$85.74**	**$78.25**	**-8.7%**
Notes Values may not sum due to rounding AESC 2009 levelized (2010-2024) AESC 2011 levelized (2012-2026)			

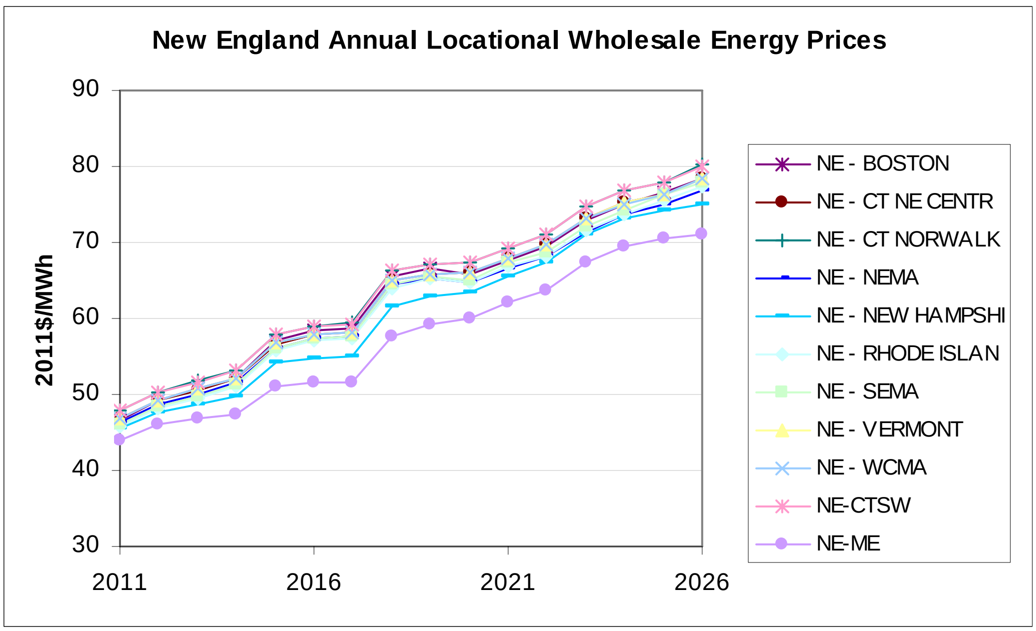
As indicated previously the AESC 2011 annual wholesale energy price forecast on a levelized basis (2012-2026) is 17 percent below that of AESC 2009. The natural gas price for New England electric generators is 18 percent lower, and the CO_2 price forecast is 31 percent lower. The changes in those two inputs explain the basic difference in the electric prices. About two-thirds of the reduction is associated with lower natural gas prices and the remaining one-third because of the lower CO_2 prices.

6.2.2.4. Forecast of Electric Energy Prices by State

The forecast of energy values by zone by year for each period i.e., summer on peak, summer off-peak, winter on-peak, winter off-peak are presented in Appendix C.

Exhibit 6-23: illustrates the summer peak period prices in descending order by model locations.[138] Note how some zones have nearly identical prices. The highest price zone is southwestern Connecticut and the lowest price zone is Maine. The price dip after 2020 is related to the underlying Henry Hub natural gas price discussed previously.

Exhibit 6-23: New England Summer Peak Locational Price Forecast



Transmission Energy Losses

Our forecast for marginal energy clearing prices includes inter-area losses for energy coming inside the load area from outside for flows across transmission links between modeling zones. These losses are not reported by the model by time of day; therefore we have presented the loss factors for summer and winter periods only. The losses are presented in Exhibit 6-24 as a percentage of imports into each zone or state.

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[138]The prices for the Bangor Hydro Area in 2024 are somewhat anomalous and will be corrected.

Exhibit 6-24: AESC 2011 Modeling Zone and State Transmission Losses

Modeling Zone Losses		
Modeling Zone	**Summer**	**Winter**
Connecticut- Northeast	8.8%	8.7%
Connecticut- Southwest	8.7%	8.7%
Connecticut- Norwalk	1.0%	1.3%
Massachusetts- Boston	4.1%	3.5%
Massachusetts- NEMA	10.0%	10.0%
Massachusetts- SEMA	2.2%	2.2%
Massachusetts- WCMA	5.1%	5.9%
Maine	10.5%	9.9%
New Hampshire	8.8%	8.7%
Rhode Island	7.5%	7.4%
Vermont	8.5%	7.8%
New England Average	6.6%	6.5%
State Losses		
State	**Summer**	**Winter**
Connecticut	6.4%	6.4%
Massachusetts	6.2%	6.2%
Maine	10.5%	9.9%
New Hampshire	8.8%	8.7%
Rhode Island	7.5%	7.4%
Vermont	8.5%	7.8%
New England Average	6.6%	6.5%

6.3. Demand-Reduction-Induced Price Effects (DRIPE) – Capacity and Energy

This section describes our estimates of capacity DRIPE and energy DRIPE.

DRIPE refers to the reduction in prices in the wholesale markets for capacity and energy, relative to the prices forecast in the Reference Case, resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.

Our estimates indicate that the DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

We estimate DRIPE in each wholesale market in three steps.

- First, we estimate the impact a reduction in load will have on the price in that wholesale market, assuming all else is held constant (Gross DRIPE).

We estimate this impact by analyzing the relationship between the quantity of capacity or energy required in the relevant market and the market price;

- Second, we estimate the pace at which market participants will respond to the reduction in price with actions that offset that reduction and ultimately cause the market price to eventually return to where to the level it would have been under the Reference Case (Net DRIPE). To estimate the pace of this offset or dissipation we estimate the material differences in actions that suppliers would take each year in the DRIPE case relative to the actions they are projected to take under the Reference Case. The pace of dissipation of capacity DRIPE will likely be different from the pace of energy DRIPE, because of the differences in the types of responses available to participants in those markets. Estimating the dissipation of DRIPE involves the exercise of considerable judgment and reasonable analysts may develop different estimates;
- Third, we estimate the percentage of net DRIPE that retail customers will experience based upon the portion of their supply that is acquired from wholesale capacity and energy markets.

6.3.1. Capacity DRIPE

Reductions in peak demand from energy-efficiency programs will have a downward effect on wholesale capacity prices because the lower demand will allow lower-cost resources to be at the margin—and set the price—in the FCAs. This impact is referred to as capacity DRIPE.

The timing of this impact will vary according to how, if at all, the reduction in peak demand is bid into the Forward Capacity Market.

- Reductions in peak demand that are bid into a FCA will explicitly reduce the clearing price in that FCA, potentially reducing FCM prices starting in the year the demand reduction measure is implemented;
- Reductions in peak demand that are not bid into FCAs will eventually reduce the ISO's forecast of peak load and hence of installed capacity requirement in the FCA and thereby eventually implicitly reduce FCA prices. Thus, the impact of those peak reductions may be delayed two to three years.[139]

Capacity DRIPE will not necessarily persist as long as the underlying demand reductions. The lower energy prices will tend to change the mix of generation used

[139]The ISO has not yet developed a method for explicitly recognizing energy-efficiency installations that are not bid into the market until they occur and reduce metered load.

to supply the market, which in turn will eventually lead to higher prices, erasing the effects of lower loads.

Our estimate of capacity DRIPE is based on the following three factors:

- The effect of reductions in peak demand on wholesale capacity prices, if all other capacity and Demand Response (DR) resources participating in the FCM did not change as a result of capacity DRIPE. We estimate capacity DRIPE based upon the supply curve observed in FCA 4 with extrapolations below and above the observed curve. This capacity supply curve is presented in Exhibit 1-9.
- The pace at which market participants will respond to lower wholesale capacity prices and eventually dissipate capacity DRIPE; and
- The percentage of capacity costs, and hence capacity DRIPE, that will flow through to retail customers each year.

Thus total capacity DRIPE is the product of the direct effect from the first factor, times the percent of the effect not yet eliminated by market participant adaptation from the second factor, times the percentage of capacity DRIPE that flows to retail customers from the third factor.

6.3.1.1. Estimate of Gross Capacity DRIPE

As described in Section 6.1, current ISO rules impose a floor price on FCM prices through FCA 6.[140] Under our Reference Case FCM prices increase between FCA 7 (June 2016–May 2017) and FCA 13 as increasingly expensive existing capacity resources set the price. From FCA 13 onward the Reference Case projects FCM prices will be set by increasingly expensive generic new additions.

We estimate capacity DRIPE from FCA 7 through FCA 13 based upon the supply curve observed in FCA 4 with extrapolations below and above that observed curve.

- In FCA 7 to FCA 10, peak load reductions would allow additional existing resources to delist. Based on the slope of the lower end of the supply curve from FCA 4 (i.e., below $4/kW-month, corresponding to the last 600 MW to drop out of the auction), we estimate that a load reduction that increases

[140] Docket Nos. ER10-787-000 et al., Order on Paper Hearing and Order on Rehearing (April 13, 2011) FERC has suggested that the floor may need to be extended another year or two to accommodate the ISO consultation process regarding other aspects of the FCA (Ibid, p. xx). Our analysis assumes this extension is not approved. If the floor is extended, the avoided FCM price would be higher during the applicable period and capacity DRIPE would be zero in that period.

supply or reduces NICR by 100 MW would reduce the clearing price by about 16¢/kW-month.

- In FCA 11 to FCA 13, peak load reductions would slow the increases in price by varying rates, from 5¢ to 49¢/kW-month per 100 MW, following the supply curve shown in Exhibit 1-9. The specific annual DRIPE values vary because of the variations in the slope of the capacity supply curves observed in the completed capacity auctions. In the price range just above the historical floor prices, the slope has been fairly steep for a small MW range (which we model as 40¢/kW-month per 100 MW over a range of 200 MW), followed by a very shallow stretch (5¢/kW-month per 100 MW) over the next 400 MW, followed by a steep rise (to 50¢/kW-month per 100 MW) as low-cost new resources are required to meet demand.

After FCA 13, the load reduction would slow the more gradual asymptotic rise in price toward the cost of generic new units, reducing prices by about 25¢/kW-month per 100 MW in FCA 14, gradually declining to 3¢/kW-month in FCA 17.

Exhibit 6-25 shows the supply and demand curve for FCA 7 to illustrate the capacity DRIPE effect:

Exhibit 6-25: FCA 7 Supply and Demand Curve

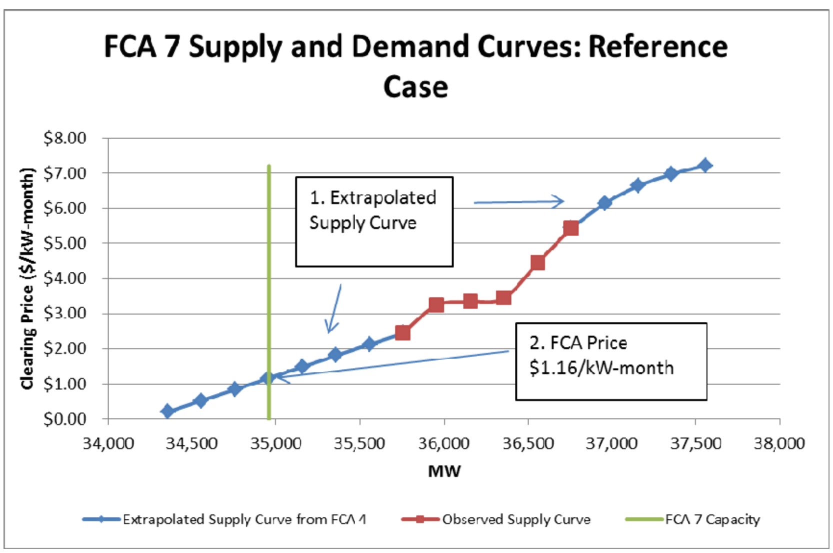

Exhibit 6-26 presents an illustrative supply and demand curve responding to decrease in capacity of 100 MW to demonstrate the gross DRIPE effect:

Exhibit 6-26: Gross Capacity DRIPE Response

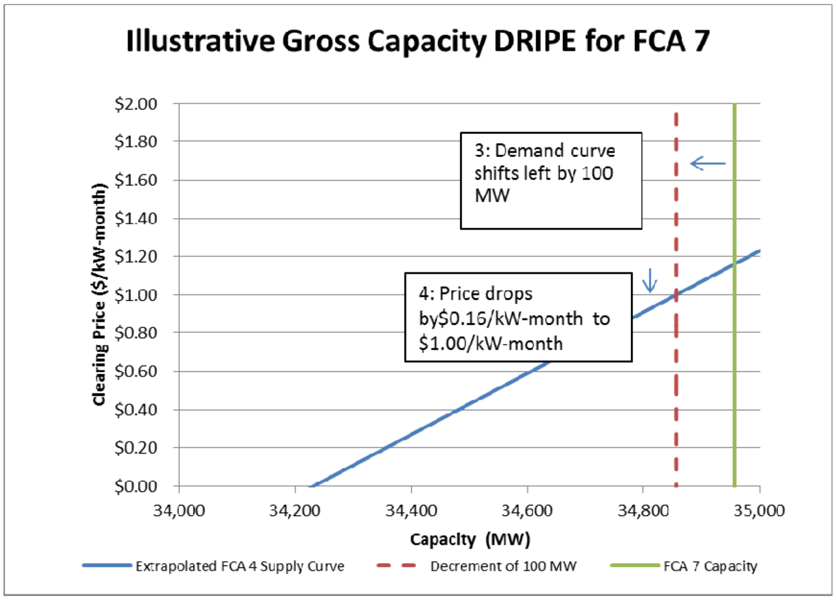

Exhibit 6-27 shows an illustrative supply and demand curve responding to the gross capacity DRIPE effect to demonstrate the net DRIPE effect:

Exhibit 6-27: Net Capacity DRIPE Response

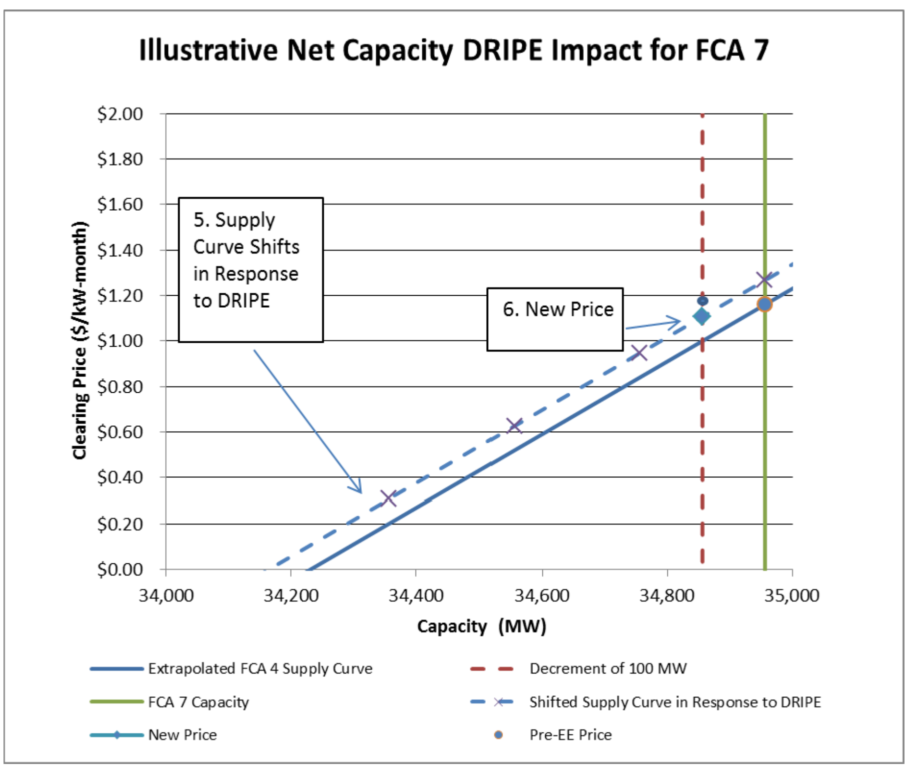

Exhibit 6-28 shows our estimates of the reduction in capacity price for a 100 MW change in the requirement for other resources due to new energy efficiency reductions starting in 2012 or in 2013. The jump in DRIPE in FCA13 reflect the point at which the supply curve transitions from keeping existing resources available to the much higher prices of bringing on new resources.

Exhibit 6-28: Capacity Prices (2011$) for the Reference Case and a 100-MW Decrement in Requirements

		FCM price to Load $/kW-month				
	Start Year	Reference Case	100 MW Reduction in Resource Need	Potential DRIPE	NICR Reserve Margin	ICR Reserve Margin
FCA2	2011	$3.60	$3.60	-		
FCA3	2012	$2.89	$2.89	-		
FCA4	2013	$2.84	$2.84	-		
FCA5	2014	$2.84	$2.84	-		
FCA6	2015	$2.84	$2.84	-		
FCA7	2016	$1.16	$1.01	$0.16	12.8%	16.0%
FCA8	2017	$1.71	$1.56	$0.16	13.0%	16.2%
FCA9	2018	$2.39	$2.24	$0.16	13.2%	16.3%
FCA10	2019	$2.68	$2.53	$0.15	13.3%	16.4%
FCA11	2020	$3.76	$3.71	$0.05	13.5%	16.5%
FCA12	2021	$3.83	$3.78	$0.05	13.6%	16.6%
FCA13	2022	$5.75	$5.25	$0.50	13.8%	16.8%
FCA14	2023	$6.92	$6.68	$0.25	14.0%	16.9%
FCA15	2024	$7.57	$7.45	$0.12	14.1%	17.0%
FCA16	2025	$7.86	$7.80	$0.06	14.3%	17.1%
FCA17	2026	$8.03	$8.00	$0.03	14.4%	17.3%

We develop estimates of intrastate and regional net capacity DRIPE by adjusting these potential Capacity DRIPE values for three factors: capacity-market response to reduced prices, utility capacity entitlements (which are not exposed to FCA prices) and reductions in renewable capacity constructed to meet RPS requirements.

6.3.1.2. Estimate of Capacity DRIPE Dissipation

As noted above, a reduction in peak load will reduce projected capacity prices relative to the levels in the Reference Case because less expensive resources will set the FCA price. Reductions in capacity prices from small reductions in peak load might continue indefinitely. However, planned energy-efficiency peak load reductions in New England are running about 300 MW annually, so the total reduction due to 2012 and 2013 installations may be on the order of 600 MW. A demand reduction of that magnitude would reduce prices by almost $1/kW-month, i.e., 600 MW * 0.16 per 100 MW for FCA 7 through FCA 10. Reductions in capacity prices of that magnitude would cause market participants to change the capacity and DR resources they bid into the FCM.

The question then is, what changes would market participants make relative to their actions in the Reference Case, and over what time period would they make these changes? One needs to project answers to those questions in order to estimate the number of years it will take for the capacity DRIPE to dissipate, i.e. for capacity prices to reach the levels forecast in the Reference Case. Estimating this dissipation or decay requires estimates of the material differences in the behavior of consumers and suppliers, relative to their actions projected under the Reference Case.

Our estimate of the dissipation of capacity DRIPE is based on our analysis of the following four factors:

1. Decisions by owners of existing capacity to accelerate the timing of delisting or retirement. We assume that accelerated retirements of existing capacity starting in 2016 will offset two-thirds of the reduction in capacity prices. Significant reductions in wholesale capacity prices, in conjunction with increased environmental costs (e.g., NOx limits under the CATR and regional haze rules, cooling-system upgrades) would almost certainly trigger additional retirements of low-capacity-factor, inefficient oil/gas steam plants.

2. Decisions by developers to change the quantity, type and/or timing of new capacity. Significant reductions in wholesale capacity prices may also cause delays in the addition of new capacity. Those delays are reflected in the supply curve in Exhibit 6-29 of the capacity section.

3. Reductions in capacity from renewable resources. Our analysis assumes that reductions in peak demand from energy efficiency measures will be accompanied by corresponding reductions in annual energy use. In turn, lower annual energy use will result in less renewable energy being required to comply with the RPS. The net result will be less new renewable resources and less new capacity from those resources. We estimate that the quantity of renewable capacity reduced by a kilowatt reduction in peak load from energy-efficiency savings will be equal to the load-weighted regional average Class-I RPS requirement percentage for energy, computed from the requirements in Chapter 2.

4. Retail customer response to lower wholesale capacity prices, increasing their electricity use and hence muting the price reduction, i.e. price elasticity.

Reductions in wholesale capacity prices will reduce retail rates, but by a very small amount, and thus should result in a minimal increase in peak load. Wholesale capacity costs are likely to be less than 20 percent of total retail electricity rates energy prices for typical load in the next couple years. Our analyses indicate that price elasticity offsets less than 5 percent of energy DRIPE which implies a price elasticity offset of capacity DRIPE of about 1 percent, which is well within the range of uncertainties.

6.3.1.3. Portion of Capacity DRIPE seen by Retail Customers: Capacity Estimate of Capacity Effect of Utility Capacity Entitlements

The effect of peak load reductions on capacity price is limited to the capacity paid the market price by load. Were all retail power supply provided under cost-of-service pricing or long-term contracts, a short-term reduction in wholesale market prices would have little effect on retail supply prices paid by customers. At the other extreme, if retail customers were being supplied 100% from the spot market and short-term contract, they would experience the benefits of short-term reductions in wholesale market prices fully and immediately. The actual mix of power supply under contract for various periods into the future varies among the states, among the utilities within some states, between municipal utilities and independently owned utilities (IOUs), and between customers on standard utility offer (standard service, default service, last-resort service, etc.) and those served by competitive suppliers. The mix also differs between capacity and energy. The standard-offer mixes are subject to legislative and/or regulatory change.

In addition, some restructured IOUs have contracts with generators for energy and capacity, which is sold into the market for the benefit of customers. These contracts include pre-restructuring contracts with independent power producers, as well as post-restructuring contracts in

- Connecticut, for:
    - A group of resources contracted to reduce Federally Mandated Congestion Costs (FMCC), including the Kleen combined-cycle plant, the Waterbury and Waterside peakers,
    - Peakers at Devon, Middletown and New Haven, and
    - Several smaller baseload renewable and fuel cell plants selected in the Project 150 process; and
- Massachusetts, for renewable purchases, currently limited to an approved National Grid contract with Cape Wind, and NStar's purchases of wind power under its NStar Green program and proposed purchases from three

more wind plants, but potentially reaching 3% of energy requirement for the utilities other than National Grid.[141]

- Rhode Island, for renewable purchases of 90 MW of average energy, phased in from 2010 through 2013.

The non-restructured utilities in New England comprise PSNH, the Vermont utilities, and the municipal and co-op utilities in Massachusetts and Connecticut.

- For PSNH, the 2010 IRP indicates that about 61% of energy and 51% of capacity requirements over the period 2012–2015 are served from owned generation and long-term contracts, assuming no migration to retail competition.[142] We assume those percentages of long-term supply will stay constant over the study period.
- For Vermont, we estimate that 90% of energy requirements are served from owned generation and long-term contracts in 2009, including about 38% from the contract between Vermont Yankee and the Vermont utilities, which ends in March 2012.[143] About 30% of Vermont's 2009 energy came from long-term contracts with Hydro Quebec that will phase out from 2013 through 2016, but will be largely replaced by a new 225 MW contract. In addition, the Vermont utilities have been committing to renewable purchases through feed-in tariffs and contracts with larger facilities. Hence, we estimate the portion of Vermont energy supply whose price will not be affected by post-2010 DSM to be about 90% in 2011, 70% in 2012, 52% in 2013, and 50% thereafter. For capacity, we assume that these values will be higher, about 95% in 2011, 75% in 2012, and 60% thereafter.
- We have no comprehensive information about the energy supplies of the publicly-owned utilities. Various municipal utilities have wholly-owned generation (mostly peaking), shares in generators owned or co-owned by MMWEC and CMEEC, ownership interests in Seabrook and Millstone, long-term contracts for the output for particular generators, contracts for supply from the New York Power Authority, and various firm purchase arrangements. Lacking any more specific information, we assume that 95%

[141] National Grid also owns about 6 MW of peakers on Nantucket, maintained as backup for the submarine transmission lines serving the island. This amount is within the uncertainties in the capacity of the other resources.

[142] Public Service Company of New Hampshire, Least Cost Integrated Resource Plan, September 30, 2010, Exhibits V-8 and V-9.

[143] Vermont Department of Public Service Utility Facts, March 2011.

of municipal-utility and co-op energy and capacity supply are under contract for 2011, decreasing 5% annually through 2018, and remaining at 60% thereafter.

For AESC 2011, we have updated our analysis of the energy and capacity that restructured utilities receive from pre-restructuring contracts, using data provided by NStar, utility filings with regulators, and FERC Form 1 data.

Exhibit 6-29: Capacity Entitlements of Restructured Utilities (MW)

	Old IPP Contracts		Renewables				Connecticut IOU Contracts				**Total**
Year	CL&P	NStar	NGrid RI	NGrid MA	FGE, WMECo	NStar	Peakers	FMCC	Project 150		
2011	448	384	44		-	-	376	786	23		2,061
2012	439	294	61		2	6	506	786	87		2,180
2013	427	293	78	87	2	6	506	786	150		2,334
2014	357	290	95	87	2	6	506	786	150		2,278
2015	109	290	95	87	7	28	506	786	150		2,057
2016	58	170	95	87	7	28	506	786	150		1,887
2017	32	20	95	87	7	28	506	786	150		1,711
2018	30	20	95	87	7	28	506	786	150		1,708
2019	23	20	95	87	7	28	506	786	150		1,702
2020	21	20	95	87	7	28	506	786	150		1,700
2021	1	20	95	87	7	28	506	786	150		1,680
2022	1	20	95	87	7	28	506	786	150		1,680
2023	1	7	95	87	7	28	506	786	150		1,666
2024	0	0	95	87	7	28	506	786	150		1,659
2025			95	87	7	28	506	786	150		1,659
2026			63	87	7	28	506	786	150		1,627
2027			46	87	7	28	506	786	150		1,610
2028			29	87	7	28	506	786	150		1,593
2029			12	87	7	28	506	786	150		1,575
2030			12	87	7	28	506	786	150		1,575

Exhibit 6-30 combines these long-term contracts of the restructured utilities with our estimates of the long-term capacity entitlements of the non-restructured utilities.

Exhibit 6-30: Summary of Long-Term Capacity Entitlements (MW)

Year	IOU Contracts	VT	PSNH	MA Munis	CT Munis	Total	% of ISO ICR
2011	2,061	1,195	1,218	3,029	494	7,998	25%
2012	2,180	927	1,206	2,819	459	7,592	24%
2013	2,334	746	1,219	2,682	436	7,416	23%
2014	2,278	769	1,267	2,608	424	7,346	22%
2015	2,057	767	1,270	2,442	397	6,932	21%
2016	1,887	775	1,296	2,313	375	6,646	20%
2017	1,711	783	1,320	2,179	353	6,345	19%
2018	1,708	794	1,344	2,039	330	6,215	18%
2019	1,702	802	1,368	2,064	334	6,270	18%
2020	1,700	810	1,390	2,090	337	6,327	18%
2021	1,680	819	1,414	2,118	341	6,372	18%
2022	1,680	828	1,438	2,146	345	6,438	18%
2023	1,666	837	1,463	2,173	349	6,489	18%
2024	1,659	846	1,488	2,202	353	6,548	18%
2025	1,659	856	1,514	2,230	357	6,616	18%
2026	1,627	865	1,540	2,259	362	6,652	17%
2027	1,610	874	1,565	2,287	366	6,701	17%
2028	1,593	883	1,591	2,316	370	6,752	17%
2029	1,575	892	1,618	2,345	374	6,803	17%
2030	1,575	901	1,644	2,374	378	6,872	17%

We decrease the ISO-wide capacity DRIPE by ratio of capacity entitlements to total ISO capacity.

6.3.1.4. Estimate of Net Capacity DRIPE

We estimate the net Capacity DRIPE for New England by taking the DRIPE effects in Exhibit 6-28 and reducing them first by the market effects and then by the long-term capacity entitlements. These offsets are grossed by the reserve margin to reflect the fact that one MW of load reduction results in more than one MW of avoided supply requirement. The results are presented in Exhibit 6-31.

The capacity DRIPE values are zero in 2011 through 2015, due to the price floors. The net effect of any single year's efficiency program on price would be quite small. For example, we estimate the net DRIPE effect in 2022,the year with the highest estimated DRIPE effect, of a 100 MW load reduction, or about 0.3% of ISO load, to be 15¢/kW-month, which would be about 2% of the FCA cost to load of $5.75/kW-month, including ICR reserves.

Exhibit 6-31: Final Regional Capacity DRIPE Values

Year	Gross DRIPE $/kW-Month per 100 MW	Market Response Offset	Aggregate RPS	NICR Reserve Margin	DRIPE $/kW-Mo per 100 MW Before Entitlements	Reduction for Entitlements	DRIPE Change in FCA Price $/kW-Mo per 100 MW	ISO NICR (MW)	ISO-wide Net Capacity DRIPE $/kW-yr
	a	b	c	d	e	f	g	h	i
2011			5%			25%		32,399	
2012			6%			24%		31,848	
2013			7%			23%		32,076	
2014			8%			22%		33,137	
2015			10%			21%		33,099	
2016	$0.16	67%	11%	12.8%	$0.053	20%	$0.042	33,593	$171
2017	$0.16	67%	12%	13.0%	$0.052	19%	$0.042	34,076	$174
2018	$0.16	67%	13%	13.2%	$0.052	18%	$0.042	34,542	$175
2019	$0.15	67%	14%	13.3%	$0.049	18%	$0.040	34,982	$169
2020	$0.05	67%	15%	13.5%	$0.016	18%	$0.013	35,470	$56
2021	$0.05	67%	15%	13.6%	$0.016	18%	$0.013	35,964	$57
2022	$0.50	67%	16%	13.8%	$0.160	18%	$0.131	36,452	$574
2023	$0.25	67%	16%	14.0%	$0.078	18%	$0.064	36,946	$284
2024	$0.12	67%	17%	14.1%	$0.037	18%	$0.030	37,448	$136
2025	$0.06	67%	17%	14.3%	$0.019	18%	$0.015	37,956	$70
2026	$0.03	67%	18%	14.4%	$0.008	17%	$0.007	38,471	$30

Notes: a. From Exhibit 6-28
b. See text.
c. Computed from Exhibit 6-37.
d. From Exhibit 6-28.
e [a] × [1–b] × [1–c] × [1+d]
f. From Exhibit 6-3.
g. [e] × × [1–f]
h. From 2011 CELT
i. [f] × [g] × 12 months ÷100

The DRIPE values in Exhibit 6-31 are for all ISO load. Values for capacity DRIPE in individual states are presented in Exhibit 6-32.

Exhibit 6-32: State Capacity DRIPE Values

	DRIPE $/kW-Mo per 100 MW Before Entitlements	State Peak Forecasts						State Capacity Requirement Hedged by Entitlements						State Net Capacity DRIPE $/kW-yr					
		CT	ME	MA	NH	RI	VT	CT	ME	MA	NH	RI	VT	CT	ME	MA	NH	RI	VT
2016	$0.053	7,800	2,210	13,945	2,650	2,020	1,145	21%		17%	43%	4%	60%	$44	$16	$83	$11	$14	$3
2017	$0.052	7,890	2,240	14,125	2,695	2,045	1,155	20%		15%	43%	4%	60%	$44	$16	$85	$11	$14	$3
2018	$0.052	7,975	2,275	14,300	2,740	2,070	1,170	20%		14%	43%	4%	60%	$45	$16	$87	$11	$14	$3
2019	$0.049	8,060	2,300	14,460	2,785	2,090	1,180	20%		14%	43%	4%	60%	$43	$15	$83	$11	$13	$3
2020	$0.016	8,135	2,330	14,620	2,825	2,110	1,190	20%		14%	43%	4%	60%	$14	$5	$28	$4	$4	$1
2021	$0.016	8,197	2,353	14,746	2,858	2,127	1,199	19%		14%	43%	4%	60%	$14	$5	$28	$4	$4	$1
2022	$0.160	8,260	2,376	14,874	2,892	2,143	1,208	19%		14%	43%	4%	60%	$146	$52	$280	$36	$45	$11
2023	$0.078	8,324	2,400	15,003	2,927	2,160	1,217	19%		13%	43%	4%	60%	$72	$26	$138	$18	$22	$5
2024	$0.037	8,388	2,424	15,132	2,961	2,177	1,226	19%		13%	43%	4%	60%	$34	$12	$66	$8	$11	$2
2025	$0.019	8,452	2,448	15,263	2,996	2,194	1,235	18%		13%	43%	4%	60%	$18	$6	$34	$4	$5	$1
2026	$0.008	8,517	2,472	15,395	3,032	2,211	1,244	18%		13%	43%	3%	60%	$8	$3	$14	$2	$2	$1

6.3.1.5. Comparison to AESC 2009 Capacity DRIPE Estimates

Due to the difference in timing, direct comparisons of the AESC 2011 Capacity DRIPE results to those in AESC 2009 are complex. The regional capacity DRIPE estimates, stated in 2011 dollars, are shown in Exhibit 6-33.

Exhibit 6-33: Comparison of AESC 2009 and AESC 2011 Capacity DRIPE

	Net Capacity DRIPE 2011$/kW-yr	
Year	AESC 2009	AESC 2011
2011	0	0
2012	0	0
2013	$115	0
2014	$170	0
2015	$112	0
2016	$43	$171
2017		$174
2018		$175
2019		$169
2020		$56
2021		$57
2022		$574
2023		$284
2024		$136
2025		$70
2026		$30
Levelized (2012-2026)	$32.80	$120.76

In present-value terms, the AESC 2011 Capacity DRIPE estimates total about 3.7 times those in AESC 2009. These higher estimates are primarily due to our projection of higher capacity prices and to a longer period for these impacts to dissipate.

The AESC 2009 study assumed that the change in capacity price would be about $0.05/kW-year for every 100 MW of reduced requirement, before market response and entitlements, for five years after EE implementation. That estimate was based on a high-level estimate of delists at prices below $3/kW-month. The AESC 2011 estimate is three times as high as the AESC 2009 estimate for the first five years after EE implementation. It averages about four times the AESC 2009 estimate from 2019 to 2026.

The AESC 2009 study assumed that the capacity DRIPE would dissipate linearly over the fourth and fifth years following the implementation of the energy-efficiency measures. This resulted in different DRIPE effects in 2013 (for example) from 2010 and 2011 peak load reductions. Given the extension of the price floor, we now do not expect any DRIPE effect until 2016. From 2016 onward we have modeled capacity DRIPE using a specific and reasonable supply curve.

6.3.2. Energy DRIPE

Energy-efficiency measures installed in any one year will have an immediate downward effect on energy prices because the lower load growth will allow lower-cost resources to be at the margin—and set the price—in more hours. This impact is referred to as energy DRIPE. Those price effects will not necessarily persist as long as the underlying energy savings. The lower energy prices will tend to change the mix of generation used to supply the market, which in turn will eventually lead to higher prices, erasing the effects of lower loads.

DRIPE in the energy market was estimated based on the following three factors:

- The effect of load reduction on market energy prices, if all energy traded in the spot market and the supply system did not change as a result of DRIPE effects. We estimating these effects based upon an analysis of historical data for loads and prices.
- The pace at which supply will adapt to energy-efficiency load reductions; and
- The percentage of power supply to retail customers that is subject to market prices in the current year and each future year.

Thus total energy DRIPE is the product of the direct effect from the first factor, times the percent of the effect not yet eliminated by supply adaptation from the second factor, times the percentage of power supply that is subject to market prices from the third factor. The DRIPE value may differ by month (or season) and zone.

6.3.2.1. Estimation of energy DRIPE via Analysis of Historical Data

Our estimation of gross energy DRIPE is based upon an analysis of the historical variation in locational energy market prices as a function of variation in zonal and regional loads. This approach is similar to that used in both AESC 2009 and AESC 2007.

The historical analysis is a regression of day-ahead hourly zonal price in dollars per MWh against both day-ahead load in the zone and day-ahead load in the rest of the ISO control area (rest of pool, or ROP). If one of the resulting coefficients was implausible, the zonal price was regressed based on total pool load and the resulting coefficient was then used for both the own-zone and ROP load. These analyses were performed separately for on- and off-peak hours, since we expected (and generally observed) that the slope of market price as a function of load would be higher on-peak.

To minimize the effect of changes in fuel prices,

- Each month was analyzed separately,
- We used data from December 2005 through April 2009, covering both high- and low-priced periods,
- We normalized the DRIPE coefficient for each of the 41 months by dividing the load coefficient by the average Hub price for the month, and
- We averaged the normalized DRIPE coefficient over the three or four years of regressions.

The regressions were calculated for on-peak and off-peak periods by month by state. Unlike AESC 2009, the regressions incorporated regional daily gas prices, measured as the spot price at Algonquin citygates. Where the regression of zonal price on zonal load, rest-of-pool load, and gas price was sensible (the zonal coefficient was greater than the rest-of-pool coefficient, and all coefficients were positive), we used the zonal and rest-of-pool coefficients from that regression. Otherwise, we used simpler regressions (omitting gas price and/or using ISO load, rather than separate zone and rest-of-pool loads).

The results by energy pricing zone show the change in the energy price in the zone as a result of a one-megawatt change in load in the zone or a one-megawatt change in load elsewhere in the ISO (the rest of pool or ROP). These results indicate that a reduction of one MWh of hourly load in a zone typically reduces price in that zone by between zero and 4¢/MWh. A reduction of one MWh of load elsewhere in the Pool typically reduces prices from zero and 5.2¢/MWh. In percentage terms we estimate that a 0.007% reduction in ISO average load results in a 0.010% to 0.022% reduction in prices in the zone where the reduction occurs, ratios ranging from 1.4 to 3.1, and a reduction of 0.007% in prices in other zones (a ratio of 1.0),

The effect of energy DRIPE on prices is typically higher in the on-peak period than in the off-peak period. Our estimates of gross DRIPE for intrastate reductions and rest of pool reductions are presented in Appendix B.

The total effect on the regional prices in a particular month, if all transactions moved with the day-ahead market price, would be the sum of the following two components:

- The average hourly load in the zone times the zonal effect, and
- The sum over zones of the average hourly zonal load times the effect of ROP load on that zone.

Exhibit 6-34 below summarizes our results for potential DRIPE effects, by month and annualized (using historical average ratios of monthly forwards to annual averages), expressed as a multiple of the Hub price in the corresponding period. Under each state, Exhibit 6-34 shows the price savings for consumers in that state and in the rest of the pool. For example, averaged over the year, a MWh saved on-peak in Maine would reduce Maine market energy bills by about 0.14 or 14% of the Hub price for a MWh of energy and bills in the rest of the pool about 1.13 or 113% of the Hub price.

Exhibit 6-34: Potential DRIPE as Multiple of Hub Price, in-State and Rest of Pool

	ME		NH		VT		CT		RI		MA	
	ME	ROP	NH	ROP	VT	ROP	CT	ROP	RI	ROP	MA	ROP
On-Peak												
Jan	0.18	0.96	0.29	0.95	0.08	0.98	0.70	0.72	0.18	0.98	0.77	0.64
Feb	0.20	1.25	0.24	1.24	0.10	1.28	0.66	0.96	0.21	1.27	0.71	0.74
Mar	0.15	0.94	0.09	0.93	0.10	0.97	0.35	0.71	0.17	0.96	0.51	0.56
Apr	0.08	0.59	0.10	0.58	0.08	0.60	0.29	0.38	0.24	0.60	0.39	0.40
May	0.12	0.87	0.12	0.85	0.04	0.87	0.46	0.52	0.27	0.88	0.35	0.58
Jun	0.08	1.24	0.36	1.23	0.06	1.25	0.75	0.80	0.08	1.24	0.81	0.81
Jul	0.14	1.70	0.43	1.70	0.11	1.76	1.23	1.29	0.24	1.72	1.06	1.04
Aug	0.11	1.35	0.41	1.35	0.10	1.39	0.74	0.97	0.15	1.37	0.75	0.84
Sep	0.15	1.14	0.10	1.13	0.10	1.17	0.45	0.77	0.25	1.17	0.74	0.74
Oct	0.14	1.16	0.13	1.15	0.10	1.20	0.40	0.86	0.16	1.19	0.55	0.73
Nov	0.11	0.98	0.34	0.99	0.07	1.01	0.73	0.78	0.23	1.01	0.68	0.61
Dec	0.21	1.07	0.38	1.08	0.12	1.10	0.53	0.82	0.17	1.09	0.71	0.66
Off-peak												
Jan	0.13	0.86	0.23	0.86	0.10	0.90	0.73	0.77	0.26	0.89	0.80	0.48
Feb	0.11	1.00	0.26	1.02	0.07	1.05	0.48	0.83	0.13	1.03	0.74	0.59
Mar	0.24	1.01	0.13	1.00	0.06	1.04	0.55	0.83	0.26	1.04	0.58	0.56
Apr	0.14	1.06	0.33	1.08	0.06	1.10	0.53	0.90	0.22	1.10	0.81	0.59
May	0.08	0.77	0.23	0.78	0.06	0.81	0.53	0.66	0.09	0.79	0.79	0.48
Jun	0.10	1.05	0.27	1.06	0.06	1.09	0.83	0.83	0.10	1.07	0.93	0.65
Jul	0.13	1.04	0.44	1.10	0.10	1.11	1.00	0.95	0.11	1.09	0.69	0.55
Aug	0.14	0.79	0.16	0.80	0.05	0.83	0.79	0.74	0.24	0.82	0.68	0.42
Sep	0.29	1.10	0.19	1.09	0.11	1.12	0.47	0.81	0.12	1.11	0.82	0.68
Oct	0.11	1.19	0.22	1.20	0.12	1.24	0.42	0.87	0.08	1.22	0.67	0.76
Nov	0.17	0.85	0.47	0.89	0.08	0.90	0.60	0.72	0.23	0.89	0.85	0.54
Dec	0.17	0.97	0.45	1.00	0.14	1.01	0.72	0.84	0.19	0.99	0.72	0.51
Average Annual												
On-Peak	0.14	1.13	0.26	1.13	0.09	1.15	0.64	0.83	0.19	1.16	0.69	0.71
Off-peak	0.15	0.97	0.28	0.99	0.09	1.02	0.65	0.82	0.17	1.00	0.76	0.56

These bill effects are potential values, assuming that the load reductions and price reductions have no effect on supply or demand, and that all energy is purchased from the short-term competitive market. We consider the impact of adjustments for changes in supply and demand in Sections 6.3.2.2 and 6.3.2.10, below.

6.3.2.2. Energy DRIPE Dissipation

As noted above, a reduction in load will reduce actual and projected prices relative to the levels in the Reference Case. More expensive generators will be used less often, high-prices price-responsive demand response will be called less often.

That reduction in prices will then tend to change the mix of resources available to supply the market. This response to lower prices is referred to as *supply adaptation.* One can think of this analysis of dissipation in terms of the following three steps:

- **The energy Reference Case.** This is a projection of the mix of supplies, and resulting energy prices, to meet the Reference Case load forecast. Those energy prices are influenced by a number of assumptions regarding decisions and actions by suppliers. In particular, decisions by suppliers regarding the quantity and type of new capacity that they will bring on-line each year influences the projected quantity of generation from that new capacity by year, and decisions by suppliers regarding the quantity and type of existing capacity that they will delist or retire each year influences the projected quantity of generation that will be removed from the total supply by year.
- **Gross energy DRIPE.** This is an estimate of energy prices in a future with a lower load forecast and the same supply curve, i.e., no reaction by suppliers. This step projects somewhat lower energy prices.
- **Energy DRIPE decay.** This step projects changes in the supply curve over time that offset the impact of the lower load forecast. This scenario projects the number of years it will take for the energy DRIPE to dissipate, i.e. for energy prices to reach the levels forecast in the Reference Case. Estimating this dissipation or decay requires estimates of the material differences in the behavior of consumers and suppliers, relative to their actions projected under the Reference Case. Specifically, DRIPE decay may be driven by the following four factors:

    1. Consumer feedback from the lower market prices, increasing electricity use and hence muting the price reduction, demand elasticity and income elasticity.
    2. Reductions in energy resources that are directly related to energy use. For example, lower energy use results in less renewable energy being required under the renewable portfolio standards, which results in higher energy prices than in the simple DRIPE case.
    3. Decisions by generation owners to change the quantity, type and/or timing of delisting or retirements of existing capacity.

        a. The owner of a baseload plant (such as a coal plant) with low variable production costs that faces major environmental investments may decide to retire or mothball the plant, due to the lower energy revenues from continued operation.[144]

   b. Even if the lower energy prices do not justify the retirement of a particular unit, the resulting lower energy prices reduce the incentive for the owner to maximize plant capacity, efficiency and availability, potentially shifting the supply curve upwards at some points, increasing market prices compared to the simple DRIPE case.

4. Decisions by generation developers to change the quantity, type and/or timing of new capacity. For example, the lower prices due to energy-efficiency investments may cause the following changes over time in the supply of conventional generation:

   a. A merchant developer may choose to develop a combustion turbine (CT) rather than a combined-cycle (CC) unit, if the CC's reduced energy revenues do not seem likely to cover its additional fixed costs.

   b. The developer of a potential CC unit will generally bid a higher price for its capacity (since energy revenues will cover less of the cost), resulting in selection of a CT in the FCM auction and hence construction of a CT rather than a CC.

   c. As the supply and demand changes in these and similar ways, energy prices will tend to increase back towards reference case levels. Once this supply adaptation has caused energy prices to recover from the effects of the load reduction, the future decisions by consumers, developers, owners, and the ISO should be essentially the same as they would have been without the load reduction. Thus, supply and demand adaptation ceases once the price effect has been extinguished.

Through about 2022, our forecast of energy prices are likely to affect primarily customer usage, RPS requirements, generator deactivations (and reactivations) and incremental improvements, and possibly the timing of municipally-owned generation additions. We examine those effects in order.

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[144]This is not a hypothetical concern, given the costs of upgrading existing coal (and some oil- and gas-fired steam) plants to meet tighter limits on air emissions and/or use of cooling water (see the retirements section in Chapter 2).

Estimating the extent of delay in adaptation of the energy market to efficiency-related load reductions is subject to considerable uncertainty, particularly in this period of capacity surplus.

6.3.2.3. Demand Elasticity Impacts

The 2011 ISO-NE forecast is based on an econometric model that estimates a short-run price elasticity of -0.05 and a long-run price elasticity of -0.091.[145]

The wholesale price of energy is just a portion of the total retail price of electricity (which also includes transmission, distribution, energy-efficiency and renewable charges, stranded costs, capacity, reserves, and ISO costs). As shown in Exhibit 6-35 the ratio of real-time energy costs, from the ISO's Wholesale Load Cost Reports, to average electricity prices, from the ISO's 2011 forecast documentation, has varied from under 30% to almost 70%, for various states and years. The spot energy prices are not the same as the forward energy prices included in retail prices, but have varied above and below forward prices in the last six years.

[145] The ISO's log-log regression includes coefficients of -0.050 on current real New England price (the short-term price elasticity) and 0.451 on the previous year's ISO energy load. The long-term elasticity equals the short-term elasticity divided by one minus the lag coefficient, or in this case, $-0.050 \div (1 - 0.451) = -0.091$. This value (to two significant values) is reached in about seven years.

Exhibit 6-35: Energy Prices and Total Electric Rates (¢/kWh)

	Connecticut				Maine				Massachusetts				New Hampshire				Vermont				Rhode Island		
	Total	LMP	Ratio		Total	LMP	Ratio		Total	LMP	Ratio		Total	LMP	Ratio		Total	LMP	Ratio		Total	LMP	Ratio
2005	12.1	7.7	64%		10.6	7.0	67%		12.2	7.6	63%		12.5	7.4	59%		12.0	7.7	65%		10.9	7.5	68%
2006	14.8	6.0	41%		11.8	5.6	48%		15.5	6.0	39%		13.8	5.8	42%		14.0	6.0	43%		11.4	5.8	51%
2007	16.5	6.6	40%		14.6	6.4	44%		15.2	6.6	44%		14.0	6.6	47%		13.1	6.8	52%		12.0	6.5	54%
2008	17.8	8.0	45%		13.8	7.5	54%		16.3	8.1	50%		14.7	7.9	54%		16.0	8.1	51%		12.3	7.9	64%
2009	18.2	4.2	23%		12.9	4.0	31%		15.5	4.2	27%		15.2	4.1	27%		14.2	4.2	30%		12.8	4.2	33%
2010	18.0	4.9	27%		13.0	4.7	36%		15.1	5.0	33%		15.1	4.9	32%		14.8	5.0	34%		13.4	4.9	36%

The average ratio is about 45%. In addition to the direct effect of energy prices, electric rates include losses on energy and the costs of risk, hedging and credit support related to the energy cost. Reserve prices are also increased by energy prices (since some energy payments are based on forgone energy revenue), but capacity prices are reduced by energy revenues. Overall, the ratio of energy-related costs to total rates may be roughly 55 percent. Thus, a one percent reduction in market energy prices would result in a 0.55 percent reduction in electric rates. These estimates result in the pattern of rebound in the energy price shown in Exhibit 6-36. In this computation, we assume that market energy prices anticipate the effects of planned energy savings, so market price declines and usage rebounds starting in the year of energy-efficiency implementation.

Exhibit 6-36: Price-Related Rebound in Energy DRIPE

Year	DRIPE Reduction
1	2.5%
2	3.6%
3	4.1%
4	4.3%
5	4.4%
6	4.4%
7	4.4%
8	4.4%
9	4.4%
10	4.5%

6.3.2.4. Income Elasticity

A significant literature exists on the extent to which bill reductions due to energy efficiency results in increased usage of energy services.[146] We investigated this effect for New England by assuming that the energy price reductions would be equivalent to increases in personal income in the ISO's 2009 CELT Forecast.[147] The forecast documentation for the New England energy forecast shows a short-run income elasticity of 0.223 and a long-run elasticity of 0.477.

The 2009 CELT forecast data show total regional electric revenues in 2000 dollars of $22.9 billion, or about 3.3 percent of the regional personal income of $699

[146] See Sorrell, S. 2007. The Rebound Effect: an assessment of the evidence for economy-wide energy savings from improved energy efficiency. UK Energy Research Centre.

[147] The 2010 and 2011 forecasts substitute gross state product for personal income, so this approach is not as easy to apply to these forecasts.

billion (also in 2000 dollars). Hence a one percent decrease in energy price, resulting in a 0.55 percent reduction in electric revenues, would be equivalent to a 0.018 percent increase in personal income, resulting in a 0.004 percent short-run increase in energy usage and a 0.086 percent long-run increase. These effects are far smaller than the uncertainties in our analysis.

Energy efficiency also reduces total bills to consumers, which may also result in some income-like effects on consumption. The extent of those effects will vary with the cost-effectiveness of the energy-efficiency investment, as well as the timing of benefits. For marginal energy-efficiency measures, which barely pass the screening tests, the net effect may well be higher bills in the initial year or two, followed by much smaller annual benefits for many years; considering the lag structure in the forecast model, the income effects of these marginal measures may slightly depress sales for several years.[148]

While some reductions in the cost of energy services (e.g., ¢/lumen-hour, or ¢/ºF) may result in consumers using more of the service, that effect should be estimated as part of the estimation of load reductions, and is beyond the scope of this analysis, which deals with the economic value of estimate load reductions.

6.3.2.5. Deferral of Renewables

Weighting the state Class-I RPS requirements in Exhibit 6-37by forecast state energy load, net of exempt load, produces the following offset to DRIPE due to reduced renewable additions.

[148] DRIPE effects are not likely to be important in decisions regarding non-marginal measures, which pass screening by a wide margin.

Exhibit 6-37: Regional Average RPS

	Average Regional Class-I RPS
2011	5.4%
2012	6.4%
2013	7.4%
2014	8.4%
2015	9.6%
2016	10.7%
2017	11.9%
2018	12.9%
2019	13.9%
2020	14.8%
2021	15.3%
2022	15.9%
2023	16.4%
2024	17.0%
2025	17.4%
2026	17.8%

The renewable-offset effect will vary among states; for simplicity, we used a regional average.

Some RPS requirements, other than the Class I requirements for new renewables and NH's Class II solar requirement, may also bring additional energy sources on line. The Connecticut Class III requirement can be met with cogeneration, but it is likely to be met entirely with credits from energy-efficiency projects that would proceed without the RECs. The Massachusetts APS is more difficult to assess, since the requirement can be met from gasification projects, cogeneration, flywheel storage, paper-derived fuel and (once regulations are developed) efficient steam technology. It is not clear to what extent this standard will be decisive in bringing on new generation. If the APS resources are flywheels, they will have little effect on overall energy price.

6.3.2.6. Reduced Incentive to Maintain and Improve Generator Performance

Most of the existing generators facing decisions about whether to retire operate at low capacity factors, so energy prices have limited effect on their economics and their presence or absence has limited effects on energy prices. The ratio of gas to oil prices and the level of environmental requirements will likely be more significant in retirement decisions of old steam plants than the price effect of efficiency programs.

On the other hand, generators face many decisions about performance improvements, maintenance, and the duration of outages, involving trade-offs between expenditures and various combinations of availability, heat rate, capacity and ramp rate. Lower energy prices are likely to tip some decisions toward delaying and reducing expenditures, resulting in more leisurely maintenance outages, poorer performance, and hence higher clearing prices. It is very difficult to estimate the effect of energy prices on those decisions and the resulting feedback to energy prices.

Considering the range of possible effect and the uncertainties, we combine the combined effects on existing generation as a one percent offset in the first year, rising one percent annually, plus five percent starting in 2016, reflecting the end of the FCM floor and the beginning of temporary reduction in the incentive to maximize capacity revenues.

We assume that generation owners and the power traders who set forward energy prices will model the effects of planned energy-efficiency efforts, so that the response will start in the same year as the energy-efficiency investment.

6.3.2.7. Deferral of New Units

If regional supply and demand were in balance, with growing load, and developers were adding a mix of peak, intermediate and baseload plants, then load reductions expected in (for example) 2014 would tend to shift the mix of new generation clearing in the 2011 forward capacity auction towards peakers, roughly offsetting the price effect of the efficiency.[149] These equilibrium conditions are not likely to occur for many years. No conventional generation appears to be needed until after 2022 and perhaps much later.

Municipal utilities can finance new generation less expensively than investor-owned utilities, independent power producers, and especially merchant developers, and may build generation before 2020.[150] The Massachusetts Municipal Wholesale Electric Company (MMWEC) has plans to add a 280 MW combined-cycle Stony Brook 3 plant in mid-2014,[151] but the unit did not qualify for FCA 5, suggesting that MMWEC is not expecting the plant to be on line in 2014. Taunton has recently suspended development of its Cleary-Flood Unit 10 combined-cycle plant, due to “Economic conditions and the resulting impact on

149 While peaking combustion turbines and intermediate combined-cycle plants can be built in three years, baseload generation (whatever that may be in the future) may have a longer lead time, resulting in some lag before the mix of new generation additions fully responds to the reduction in load.

150 Several municipal utilities (e.g., Braintree, Vermont Public Power, CMEEC) have added generation in recent years.

151 http://www.stonybrookunit3.org/progress-is-underway.html.

electricity usage and natural gas prices….”[152] Our Reference Case capacity prices are unlikely to support even these low-cost municipal units until at least 2020, and probably 2022 or later. Reduced energy prices could cause these utilities and their partners to delay the plants further, offsetting some DRIPE. It is not clear when these units would be constructed in the Reference Case, or how much energy prices would need to fall to change the timing of Stony Brook 3.

With all those caveats, we assume a 50 percent probability that the energy DRIPE of any particular increment of energy efficiency would be offset by delay of a municipal generator in 2020.[153] In subsequent years, we assume the probability of an offset increases by 10 percent each year, reaching 100 percent in 2025. While some new generation would likely be needed for the FCM by 2022, that capacity may be a peaker, or a combined-cycle operating at a capacity factor lower than the load factor of the energy efficiency, so the earliest new capacity may offset only part of the energy DRIPE remaining after other adjustments.

6.3.2.8. Summary of Energy DRIPE

Combining these four effects, we get the following pattern of energy DRIPE extinction. The demand elasticity in Exhibit 6-38 is for installations in 2012.[154]

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152 http://www.tmlp.com/press_release/2011/Unit10OnHold.pdf.

153 That 50% probability might result from, for example, a 70% chance that the unit would be built with the base-case energy prices, and a 70% chance that it would be delayed by lower prices.

154 For installations in 2013, the demand elasticity column would be shifted down one year.

Exhibit 6-38: Energy DRIPE Decay, 2012 Installations

	Demand Elasticity	RPS	Existing Generation	New Generation	Total DRIPE Offset[a]
2011		5.4%			
2012	2.5%	6.4%	1.0%		10%
2013	3.6%	7.4%	2.0%		13%
2014	4.1%	8.4%	3.0%		15%
2015	4.3%	9.6%	4.0%		17%
2016	4.4%	10.7%	10.0%		23%
2017	4.4%	11.9%	11.0%		25%
2018	4.4%	12.9%	12.0%		27%
2019	4.4%	13.9%	13.0%		28%
2020	4.4%	14.8%	14.0%	50%	65%
2021	4.5%	15.3%	15.0%	60%	72%
2022	4.5%	15.9%	16.0%	70%	80%
2023	4.5%	16.4%	17.0%	80%	87%
2024	4.5%	17.0%	18.0%	90%	94%
2025	4.5%	17.4%	19.0%	100%	100%

Note a: Total = 1–(the product of (1-factor%) over the four factors).

6.3.2.9. Comparison to AESC 2009

This analysis of the energy DRIPE decay is similar to that in AESC 2009. It is updated for new price elasticity estimates, RPS requirements, later installation dates, and a more detailed assessment of the timing of new municipal generation being built.

6.3.2.10. Share of Retail Power Supply at Current Market Prices

As discussed in the Capacity Section of this chapter, long-term utility resource entitlements, both for vertically-integrated utilities and for the legacy and special-purpose assets of some restructured utilities. The distribution of entitlement energy is sometimes quite different from entitlement capacity; for example the Connecticut peakers are operated much less than the renewable or baseload independent power producer (IPP), and the Connecticut Federally Mandated Congestion Charge (FMCC) contracts are for capacity only.

Exhibit 6-39: Utility Energy Entitlements (GWh)

	Old IPP Contracts			Renewables				Connecticut Contracts		
Year	CL&P	NStar	MA & CT Vermont Yankee	NGrid RI	NGrid MA	FGE, WMECo	NStar	Peakers	Project 150	Total
2011	2,355	2,480	516	340		26	105	33	181	6,037
2012	2,308	1,889	123	490		42	168	44	682	5,747
2013	2,244	1,883		640	760	74	296	44	1,183	7,123
2014	1,876	1,870		788	760	74	296	133	1,183	6,980
2015	571	1,870		788	760	122	487	133	1,183	5,913
2016	307	1,082		788	760	122	487	133	1,183	4,861
2017	167	96		788	760	122	487	133	1,183	3,736
2018	156	96		788	760	122	487	222	1,183	3,814
2019	123	96		788	760	122	487	222	1,183	3,780
2020	113	96		788	760	109	434	222	1,183	3,705
2021	6	96		788	760	95	382	222	1,183	3,532
2022	6	96		788	760	95	382	222	1,183	3,532
2023	6	32		788	760	95	382	222	1,183	3,468
2024	0	0		788	760	95	382	222	1,183	3,430
2025				788	760	95	382	222	1,183	3,430
2026				549	760	95	382	222	1,183	3,191
2027				399	760	95	382	222	1,183	3,041
2028				249		95	382	222	1,183	2,131
2029				101		95	382	222	1,183	1,983
2030				101		95	382	222	1,183	1,983

Note: Connecticut peaker contracts are estimated at 1% capacity factor through 2013 as forward reserve units, gradually rising to 5% as energy units. The Project 150 resources are assumed to operate at a 90% capacity factor.

Exhibit 6-40: Summary of Long-Term Energy Entitlements (GWh)

	Entitlements						ISO Net	
Year	IOU Contracts	VT	PSNH	MA Munis	CT Munis	Total	Energy for Load	Entitlements as % of ISO
2011	6,037	6,180	5,239	12,439	1,955	31,849	135,455	24%
2012	5,747	4,961	5,365	11,996	1,885	29,953	137,955	22%
2013	7,123	4,011	5,434	11,428	1,797	29,793	139,230	21%
2014	6,980	4,053	5,518	10,874	1,712	29,137	140,830	21%
2015	5,913	4,080	5,596	10,293	1,620	27,503	142,215	19%
2016	4,861	4,101	5,675	9,702	1,525	25,864	143,585	18%
2017	3,736	4,125	5,755	9,101	1,428	24,145	144,980	17%
2018	3,814	4,149	5,833	8,489	1,329	23,613	146,390	16%
2019	3,780	4,176	5,911	8,575	1,339	23,781	147,760	16%
2020	3,705	4,200	5,989	8,662	1,350	23,906	149,145	16%
2021	3,532	4,220	6,054	8,734	1,358	23,897	150,283	16%
2022	3,532	4,240	6,119	8,805	1,367	24,063	151,429	16%
2023	3,468	4,261	6,186	8,877	1,376	24,167	152,584	16%
2024	3,430	4,281	6,253	8,950	1,385	24,299	153,748	16%
2025	3,430	4,301	6,320	9,023	1,393	24,469	154,920	16%
2026	3,191	4,322	6,389	9,097	1,402	24,402	156,102	16%
2027	3,041	4,343	6,458	9,172	1,411	24,425	157,293	16%
2028	2,131	4,363	6,528	9,247	1,420	23,690	158,492	15%
2029	1,983	4,384	6,599	9,323	1,430	23,718	159,701	15%
2030	1,983	4,405	6,671	9,399	1,439	23,896	160,919	15%

Since in many cases the load that benefits from these sales is in a different zone or even state from the zone in which the resource is located (which determines the change in price received for the contract energy), we apply the contract offset as an ISO-wide average.

Most of the utilities also receive revenues from the use of Hydro-Quebec tie lines; it is not clear how those revenues are determined, or whether they vary with energy prices in New England.

Multiplying the share of the load exposed to market prices by the portion of the price effect not yet offset by supply adaptation produces an estimate of the percent of load affected by DRIPE. This can be expressed as a formula:

$$\textit{\% of load subject to energy } \textit{DRIPE} = (1 - \textit{market response}) \times \textit{\% of power supply prices at market}$$

Exhibit 6-41 summarizes the combined effect of DRIPE decay and market exposure, for each of four consumer groups: PSNH, the Vermont utilities, other municipal utilities (and the Maine coops), and the restructured investor-owned utilities (and the NH Co-op). The DRIPE decay in the first column is one minus the total DRIPE offset from Exhibit 6-38, above. The Net DRIPE Effect in Exhibit

6-41 is the produce of the DRIPE Decay and the market exposure for the various customer groups.

Exhibit 6-41: Summary of Energy DRIPE Response

	DRIPE Decay	Energy Hedged by Entitlements	Effective Energy DRIPE
2012	10%	22%	71%
2013	13%	21%	69%
2014	15%	21%	68%
2015	17%	19%	67%
2016	23%	18%	64%
2017	25%	17%	63%
2018	27%	16%	62%
2019	28%	16%	60%
2020	65%	16%	30%
2021	72%	16%	23%
2022	80%	16%	17%
2023	87%	16%	11%
2024	94%	16%	6%

Applying those percentages to the potential energy DRIPE produces the energy DRIPE. In the spreadsheets accompanying the final report, we will calculate the energy DRIPE effects of a 1 MWh reduction in energy uses in each zone, by or season.

6.3.3. Comparison of Results to Other Studies of Price Suppression

Energy DRIPE and capacity DRIPE are each forms of price suppression, a market impact which has been widely studied in the context of increased power supply. A number of studies have examined these issues, mostly in the context of incremental generation. Several of those studies are summarized in Exhibit 6-42. Full citations are provided in the bibliography attached as Appendix C.

The summary metric developed in these studies is a ratio of the percentage change in energy price to the percentage change in load or supply. For our energy DRIPE results, a MWh reduction in load (about 0.007% of ISO average load) results in about 0.007% reduction in prices in other zones (a ratio of 1.0), and about 0.010% to 0.022% in the zone with the reduction (ratios of 1.4 to 3.1). These are well within the range of reported sensitivities.

The ratios of price reduction to load reduction (or additional low-cost energy) in Exhibit 6-42 are for the entire region listed in the third column, except for Charles River 2010, which produced results for both the zone with the resource (SEMA) and the entire ISO, and Stern 2009, which estimated effects in northern and western New York State (Zone 1) from installations in that area, in the Hudson Valley (Zone 2) from installations in that area, and for the state as a whole from all procured resources (mostly in Zone 1).

Exhibit 6-42: Summary of Price-Suppression Studies

					Price Effects				Ratio of Δ price to Δ supply
	Date	**Region**	**Resource**	**Position**	**Energy**	**Capacity**	**Decay?**	**Case**	
Charles River Associates	2010	ISO-NE	Cape Wind	Support	Yes	No	No	2013-27 ISO	1.9
								2013-27 SEMA	2.7
Eggers, D., et al.	2009	ISO-NE	HQ Line	Neutral	Yes	No	**Yes**	2014	0.9
								2015	0.9
								2016	0.4
								2017	0.3
								2018	0.3
Cool, E., et al.	2010	ISO-NE	Canal Unit 2	Oppose	Yes	No	No		~1.0
Cool, E., et al.	2008	ISO-NE	Conn peakers	Neutral	Yes	**Yes**	**Yes**		490
Frayer, J., et al.	2007	ISO-NE	Conn generators	Neutral	Yes	Yes	No		NRA
Frayer, J.	2009	ISO-NE	Meriden CC	Oppose	Yes	Yes	**Yes**		NRA
MacCormack, J., et al.	2010	Alberta	Wind	Neutral	Yes	N/A	No	10% capacity	5.8
								20% capacity	4.5
Munksgaard, J., & Morthorst, P.E.	2008	Denmark	Wind	Neutral	Yes	No	No	2004	0.2
								2005	0.8
								2006	0.3
New York Department of Public Service	2008	NYPP	EE	Neutral	Yes	No		2009	0.7
								2012	0.4
								2015	0.4
PJM	2009	PJM	EE	Neutral	Yes	No	No	2%	~2.0
						No	No	5%	~2.0
						No	No	10%	~2.2

Exhibit 6-42: Summary of Price-Suppression Studies Continued

					Price Effects				Ratio of Δ price to Δ supply
	Date	Region	Resource	Position	Energy	Capacity	Decay?	Case	
Saenz de Miera, et al.	2008	Spain	Wind	Neutral	Yes	No	No	2005	1.4
								2006	0.9
								2007	2.4
Senfuss, et al.	2008	Germany	Wind	Neutral	Yes	No	~		NRA
Stern, F, et al.	2009	NYPP	Wind	Support	Yes	No	No	Zone 1	1.4
								Zone 2	1.0
								State	1.1
Blossman, B., et al.	2009	ERCOT	Wind	Neutral	Yes	N/A		2008 on A	1.4
					Yes	N/A		2008 off A	1.2
					Yes	N/A		2008 on B	2.0
					Yes	N/A		2008 off B	1.2
					Yes	N/A		2013 on A	1.2
					Yes	N/A		2013 off A	0.8
					Yes	N/A		2013 on B	1.4
					Yes	N/A		2013 off B	1.3
Notes:	N/A means no capacity market exists. NA means not applicable to this study. NRA means the necessary data are not readily available. Blossman, et al., estimate effects with constraints (2008 Case A) and without (2008 Case B), and for 100% capacity factor (2013 Case A) and realistic capacity factors (2013 Case B)								

In addition to the summary information on energy DRIPE, we detail some identified studies in more detailed attention, due to their treatment of capacity prices and/or DRIPE decay. Exhibit 6-43 summarizes the length of DRIPE effects and (for studies that included energy DRIPE through the end of the analysis) the ratio of the DRIPE effect in the last year of the analysis to the effect in the first year. A "+" in the third column indicates that the DRIPE effect continues through the end of the study period. Each of these studies reduce energy DRIPE (and the Levitan study reduces capacity DRIPE) only when the resource under study delays a new unit or retires an existing unit.

Exhibit 6-43: Summary of DRIPE Decay in Price-Suppression Studies

Study	Market	Years to End of DRIPE	% of Initial DRIPE at End of Analysis
Cool, et al, 2008 (Levitan)	Energy	11	
	Capacity	7	
Frayer, 2009 (London Economics)	Energy	12+	24%
	Capacity	12+	
Eggers, 2009 (Credit Suisse)	Energy	7+	27%

AESC 2011 estimates capacity and energy DRIPE from 2012 installations to last 11 and 13 years respectively.[155] AESC 2011 estimates capacity and energy DRIPE from 2013 installations to last 11 and 12 years. These durations are consistent with the reviewed literature.

6.3.3.1. Levitan and Associates, Connecticut Peakers

The analysis of price suppression by the proposed peakers in Connecticut concentrated on the forward reserve market, which is of little relevance for future energy-efficiency screening. In addition, Cool, et al., considered the effect of the peakers on regional capacity prices, and incorporated a form of decay in the benefits.

For the capacity market, Cool, et al. had only data from FCA 1. They estimated capacity DRIPE for FCA 5 to FCA 7, since they assumed an effective price floor through FCA 4 and a need for new generic capacity at a uniform price in FCA 8. The resulting DRIPE equivalents were $0.62, $0.12, and $0.63 per kW-month (in nominal dollars) per 100 MW of supply, compared to $0.16 to $0.50 (2011 dollars) in our estimates.

[155] For 2014 and 2015, where the potential Capacity DRIPE impact is $0 due to the FCM floor price, we do not include those years in estimate of duration for Capacity DRIPE.

In terms of DRIPE phase-out, in the capacity market Levitan terminated all DRIPE once any generic unit was needed, in FCA 8 (the summer of 2017). For energy DRIPE, Levitan continued the effect through 2020, with no obvious trend from year to year, and then ended it.

6.3.3.2. London Economics, Meriden Combined Cycle

The July 2009 testimony of Julia Frayer on behalf of Connecticut Light and Power estimated the energy and capacity market effects of adding a proposed 510 MW gas-fired combined-cycle plant in Meriden Connecticut in 2014. While many details of the analysis are difficult to extract from the public record, Frayer estimated that Meriden would reduce market prices in Connecticut by about $2.5/MWh in 2014–2016, $2.3/MWh in 2017–2018, $0.7/MWh in 2019, and $0.6 in 2020–2023. The decay of the price suppression results from the assumption that Meriden's existence would result in the retirement of an existing combined-cycle in 2017 and the delay of a small new combined-cycle in 2019.

The conclusion that the existing unit would be retired, and that the 2019 combined-cycle would have been needed in the absence of Meriden, were due to Frayer's assumption that a generator that could not cover its fixed costs over three consecutive years would retire. This might be a reasonable assumption,[156] except that Frayer included in the fixed costs debt service based on a mortgage on 60% of the plant's market value. Frayer assumes that the owner can walk away from any unit that does not cover debt payment, and that the unit will be retired. In fact, owners often cannot walk away from the debt on individual units, since the debt holders have recourse to other units owned by the operating subsidiary. More importantly, the inability to cover debt service may lead to bankruptcy and change in ownership of the unit, but does not lead to retirement. For example, Mystic and Edgar stations are now going through the second bankruptcy of an owner, but they continue to operate. PG&E National Energy Group, then owner of about 5,000 MW of New England capacity, went bankrupt in 2003; its portfolio continues to operate under other ownership. Other major merchant generators, including Calpine and Mirant, have been through bankruptcy, divested some assets, but emerged as major generators.

Despite the errors in Frayer's retirement analysis, the approach parallels parts of our treatment of DRIPE decay. Over time, DRIPE is reduced, but not eliminated, by responses of existing plants and by delay of new additions, once new capacity is required.

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[156] Other analyses, such as the Connecticut 2010 IRP, assume that owners would tolerate much longer periods of losses, so long as the unit's economics are expected to turn around.

Frayer also estimated the effect of Meriden on FCM prices (Frayer Figure 40). She assumed that lower energy prices would increase FCM bid prices by generators, probably based on her assumption that the generators prefer to retire than to bid less than required to cover hypothetical debt payments. As a result, she finds that Meriden would increase FCM prices in 2014–2016, and have almost no net effect on FCM prices in 2017 and 2019. She estimates reductions in the FCM price of about $2.2/kW-year in 2018, $1/kW-year in 2020, $4/kW-year in 2021 and 2022, and $6.5/kW-year in 2023. (The latter is equivalent to $0.08/kW-month per 100 MW in 2011 dollars.) Interestingly, Frayer estimates rising FCM price effects over time.

6.3.3.3. Credit Suisse, Hydro Quebec

A 2009 Credit Suisse analysis (Eggers 2009) compares two scenarios, a Reference Case and an adaptation case, which Eggers refers to as a new HQ import case. In his Reference Case 600 MW of combined-cycle capacity is added in 2016 and another 200 MW in 2017. In his new HQ-import case 1,125 MW of additional hydro energy is imported from HQ to ISO-NE over a new line starting in 2014. Eggers does not specify the quantity of energy that would be provided by either the HQ line or the combined-cycle units. In the new HQ capacity case the market responds by canceling the 600 MW of combined-cycle capacity planned for 2016 and the 200 MW planned for 2017 under his Reference Case.[157]

The result of the change in the supply additions, Eggers (2009) estimates that the energy price in New England would be reduced from the Reference Case by

- $5.05/MWh in 2014 and 2015 (HQ added, no supply offset).[158]
- $2.19/MWh in 2016 (600 MW of combined-cycle removed).
- $1.37/MWh in 2017–2020 (combined total of 800 MW of combined-cycle removed)

Credit Suisse’s estimate of the price effect of changes in this base/intermediate capacity is essentially linear, with energy price declining about $0.0045/MWh for each MW of capacity added and rising the same amount for each MW removed. In periods with no additional offsetting changes in capacity (2014–15 and 2017–2020), the market price effect of the HQ line does not change.

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[157] The Credit Suisse report refers to those combined-cycle additions, and further additions in 2018–2020 as “NE-ISO published” and references “Company information” (apparently referring to Northeast Utilities and NStar), but we are not aware of any such ISO or utility publication.

[158] The report authored by Eggers does not indicate whether these prices are real or nominal, but they appear to be real.

6.3.3.4. Senfuss, et al, German Wind

Senfuss, et al., do not estimate a decay in price suppression, but they do analyze the effect on price suppression in 2006 under a series of assumptions regarding the causation of the large retirements and deactivations that occurred in the period that wind capacity was increasing under the feed-in tariff. In the base case, they assume that the retirements were unrelated to the 52 TWh of wind penetration; in a series of steps, they re-estimate energy price suppression assuming that wind was responsible for part or all of the retirements and deactivations. The results are summarized in Exhibit 6-44.

Exhibit 6-44: Effect of on Wind-Related Price Suppression of Imputed Retirements

	Step 1	Step 2	Step 3	Step 4
Coal MW	402	1,951	2,812	4,007
Oil & gas MW	2,272	3,484	3,542	4,976
Change in Price Effect, from Base	1%	-28%	-43%	-58%

It is difficult to draw any detailed lessons from these results, other than that retirements can offset DRIPE. In Senfuss's Step 1, the loss of mostly oil and gas capacity has no effect on DRIPE. In the later steps, the decay rises mostly with coal retirements. By Step 4, assuming that the coal plants would have operated at 60% capacity factor and the oil and gas plants at 5%, the retired plants would have produced about 23 TWh of energy, or about 45% of the wind output, and the fossil plants would have operated at higher-price times than the wind. On the whole, Senfuss, et al., would weakly support the hypothesis that retirement of existing units will erode DRIPE in rough proportion to their expected energy output, with peaker energy reducing DRIPE at a faster rate than baseload energy, per MWh, but baseload retirements being much more important per MW.

6.3.4. Gas DRIPE

Gas DRIPE measures the reduction in wholesale market prices forecast in a reference case due to a reduction in the forecast quantity of gas commodity and/or gas pipeline and storage capacity underlying that reference case. The reduction in the forecast quantity of commodity and/or capacity could be caused by various factors including more efficient use of gas at the end-use, displacement of gas by other energy sources at the end-use, less use of gas for electric generation due to more efficient use of electricity at the end-use and less use of gas for electricity due to displacement of gas-fired generation by renewables.

An estimate of gas DRIPE, like electric DRIPE, has two components – magnitude and duration. The first component is the initial magnitude of the reduction in the reference case wholesale market price for a given reduction in gas usage. The second component is the duration of the reduction in price, i.e. the length of time it will take for the reduction in price to disappear. DRIPE disappears when market prices return to reference case forecast levels as a result of market participants taking actions they would not have taken in the reference case, e.g. not drilling wells they would have otherwise drilled.

Gas DRIPE, like electric energy DRIPE, has the potential to be a significant benefit of efficiency programs. Reductions in gas use from gas and/or electric efficiency in New England are likely to have very small effects on the wholesale commodity price of natural gas, particularly because commodity prices are set by demand and supply in the North American commodity market. However, the absolute value of a small reduction in the commodity price could be significant because it would apply to all of the natural gas consumed in New England. In addition, a reduction in gas use in New England has the potential to have an impact on the price of pipeline and storage capacity serving New England, particularly if the region needs new capacity.

6.3.4.1. Information Regarding the Existence of Gas DRIPE

The following studies have found that reductions in gas usage would reduce wholesale market prices for gas:

- "Natural Gas Efficiency Resource Development Potential in New York," Mosenthal, P., et al., October 31, 2006. Albany, N.Y.; New York State Energy Research and Development Authority.
- Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets in the Pacific West, William Prindle, et al., January 1, 2006, ACEEE.
- Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis, Elliott, RN, and Shipley, AM, April 1, 2005, ACEEE.
- Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest. Kushler, M, et al., January 2005, ACEEE.

The final AESC 2011 Scope of Work did **not** include either an analysis of the reports listed above to estimate gas DRIPE in New England or an analysis to estimate the impact a reduction in load will have upon the market price and then estimates the pace at which suppliers participating in that market will respond by taking a different set of actions than they would have taken in the reference case.

6.4. Avoided Transmission-and-Distribution Costs

We surveyed the sponsoring electric utilities to determine (1) the avoided T&D capacity cost estimates used in the valuation of 2009 DSM programs and (2) the methodology on which these estimates were based. Exhibit 6-45 summarizes the information provided:

Exhibit 6-45: Summary of Electric Utilities' T&D Estimates

Company	Year $	Transmission $kW-year	Distribution $kW-year	Source	Documentation
NStar	2008	14.41	85.28	NStar/ICF	Workbook provided
CL&P	2011	1.25	29.74	ICF report	PDF report
WMECo	2010	20.30	60.87	WMECo/ICF	None
National Grid MA	2010	19.95	109.25	NGrid/ICF	Workbook provided
National Grid RI	2010	19.95	87.13	NGrid/ICF	Workbook provided
UI	2011	2.54	45.96	B&V report	PDF report

Notes

Utility//ICF = the utility applied the 2005 ICF approach, sometimes with modifications.

B&V Report = United Illuminating Avoided Transmission & Distribution Cost Study Report, Black & Veatch, September 2009.

ICF Report = Assessment of Avoided Cost of Transmission and Distribution, ICF International, October 30, 2009.

CL&P and UI avoided costs in 2011$ are from 2011 Electric and Natural Gas Conservation and Load Management Plan; CL&P, UI, et al.; Dockets 10-10-03 and 10-10-04; October 1, 2010; page 331.

Unitil, and the Vermont and Maine program administrators did not respond to our inquiry.

A description of the ICF model used by NStar and National Grid was detailed in the AESC 2005 report. The AESC 2009 report included our review of the ICF model in general and in its use by the utilities.[159] We will not repeat that review here. The updated models provided by National Grid and NSTAR address several of the concerns identified in AESC 2009.

Two utilities are using T&D estimates derived from new studies performed after AESC 2009. CL&P had ICF prepare a new avoided-T&D analysis, using a different method than the 2005 ICF model, while UI had Black & Veatch estimate

[159] The avoided-cost analyses used by WMECo and NStar are the same as those reviewed in AESC 2009, using actual data only through 2008. See AESC 2009 pages 6-66 and 6-67 for a detailed critique of the components of the ICF model.

its avoided T&D. Our review of methodologies here offers some general observations and recommendations to ensure greater consistency and accuracy in the estimation of avoided T&D capacity costs across program administrators and methodologies.

6.4.1. General Methodology

The basic method in the ICF model, the ICF report for CL&P, and most other avoided-T&D estimates is to divide actual or expected investment by actual or expected load growth. The B&V report for UI uses a different approach, dividing the cost of each investment by the full capacity it could accommodate. Since T&D investments may be required by even small increases in load above the capacity of existing equipment, the B&V approach may not accurately reflect the savings from reducing load growth.[160] Since avoidable T&D costs are estimated as the ratio of actual or expected investment to actual or expected load growth, the costs used in the analysis are those not actually avoided.[161] Analysts do not generally have estimates of costs that have actually been (or are expected to be) avoided by energy-efficiency; such analysis would usually be prohibitively expensive.

Any single investment is unlikely to increase delivery capability all the way from the generators to the customer meter. Adding line transformers allows customers to draw more power from the primary distribution system; reconfiguring existing primary feeders maximizes the amount of regional available substation capacity that can be delivered to the line transformers, and so on.[162] Depending on the amount of excess capacity on the various levels of T&D equipment in a particular area, reducing load by any particular customer may avoid addition of a line transformer the next year, and contribute to delaying or avoiding the reconfiguration of feeders, the upgrading of a substation, and the construction of transmission lines in following years. At another location, load reductions may have little effect on T&D investment for many years. The basic approach to avoided cost estimates this complex relationship by computing the average ratio of all load-related investments to all load growth, rather than just the load growth that has the greatest effect on investment.

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[160] For example, the need for a new substation is not determined by an increment of MVA at one location, but by an increment of a few MVA that push load (normal or emergency) above the capacity of an existing substation.

[161] The B&V report appears to exclude some investments on the grounds that they were not avoided.

[162] B&V exclude some investments on the grounds that the projects only increase capacity on parts of the system.

6.4.2. Loads

All the T&D analyses provided in this round of review use the same system peak loads for both transmission and distribution capacity. For transmission, that assumption is a reasonable approximation. But the load growth on the utility's distribution system is lower, since many large customers provide some or all of their own distribution and are served at various transmission or primary-distribution voltages. Hence, the load used in the distribution analysis should generally be lower and the cost per kW higher (all else equal).

6.4.3. Tax Effects

The ICF model attempted to avoid the detailed computation of tax effects on revenue requirements. This simplification introduces a number of potential errors: 1) exclusion of taxes on the portion of nominal return that exceeds real return, 2) double-counting of the tax shield on debt, and 3) treating the difference between book and MACRS tax depreciation as if it were the same as the difference between sinking-fund and straight-line depreciation.[163]

We tested the effect of these simplifications by modifying the revenue requirements spreadsheet developed by NStar for its Lower SEMA 345 kV Transmission Project (filed in Massachusetts EFSB Docket No. 10-2) to use the input values (e.g., depreciation life, costs of capital, taxes, O&M) that NStar used for transmission in its ICF model of avoided T&D. The revenue requirements spreadsheet conducted all computations in nominal terms and explicitly computes the annual taxes reflecting accelerated tax depreciation. The real-levelized carrying charge is 11.0%, levelizing at the weighted average cost of capital, or 10.0%, levelizing at the weighted average cost of capital minus the tax shield on debt. The ICF model computes a levelized carrying charge of 10.4% with those same input values. The results may diverge more with alternative costs of capital or useful lives.

6.4.4. Investments Avoidable by Energy Efficiency

For any of the methodologies used, the utilities should review the specific projects (or the percentage of investments by category of T&D) that are assumed to be unavoidable by energy efficiency, and better document decisions to exclude the costs of those projects.

Among distribution investments, some asset accounts (primarily meters and services) are generally considered to be affected very little by energy-efficiency programs. Some distribution projects extend service into areas that have not

163

previously been served, to connect new customers; only a small portion of those pole and wire costs are potentially avoidable by load reductions.[164] Some transmission projects are required to integrate generation, or to facilitate exports, and would be affected little, if at all, by load reductions.[165] For both distribution and transmission, investments that are simply replacements in kind due to physical deterioration or required relocation of facilities are not considered avoidable. Other than these categories, the classification of investments as unavoidable should be fully and clearly justified.

The UI and CL&P reports exclude a number of projects and categories that appear at first blush to be load-related, without adequate explanation. In order to determine that a T&D investment is not load-related and hence properly includable in the avoided-cost computation, the analysis should demonstrate that

- The investment is not motivated or required by the level of actual, anticipated or emergency load. Those considerations drive the installation of most transmission lines, new substations, additional substation transformers, new feeders, reconductoring, additions of line transformers in areas with existing service, voltage upgrades, and conversion of feeders from single-phase to multi-phase.
- The investment is not motivated by load-related energy considerations, including congestion relief and reduction of line losses.
- The investment category does not increase with load. For example, higher loads result in earlier failure of line transformers, so replacements of transformers are at least partly driven by load levels.[166]

The book costs of T&D projects generally include an allocation of overhead costs. Some of those overheads may not vary with the amount of plant under construction or in service, or the number of personnel required to design, build, maintain and operate the assets. But many categories of overheads do vary with one or more of those drivers, including office space and equipment; personnel, purchasing, and other support services; warehouses, vehicles, and equipment; and

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[164] As a result of the exclusion of meters and services, as well as projects that extend the distribution system to new areas, the percentage of distribution investment that is avoidable would generally be lower than the percentage of transmission investment.

[165] Generation-related transmission investments are generally charged to the generators; if these costs are avoidable, it would be through avoiding the need for the generator, and the costs should show up in market generation prices.

[166] Some transformers are replaced because they rust out or are destroyed in accidents.

legal, financial and regulatory services. Any exclusion of overhead costs from avoided T&D should be carefully considered and fully justified.

In addition to increasing capital-recovery costs and taxes, most plant additions also require additional operating and maintenance costs. The ICF model and many other analyses of T&D project costs (including the NStar transmission analysis cited above) assume that the ratio of O&M cost to plant for the avoidable capacity is the same as for the existing plant mix.[167] Any assumption that O&M associated with a new transmission line, feeder, substation or transformer is less than the average O&M for similar existing equipment should be carefully considered and fully justified.

6.5. Regional Electric-Energy-Supply Prices Avoided By Energy-Efficiency and Demand-Response Programs

6.5.1. Avoided Cost of Compliance with RPS

Our estimate of avoided costs includes the expected impact of avoiding the region's five existing Renewable Portfolio Standards. AESC 2011 also assumes that Vermont establishes a binding RPS in addition to any and all of its current voluntary goals and renewable energy programs. The annual quantity of renewable energy that LSEs need to acquire in order to comply with RPS requirements is directly proportional to the annual load that the LSEs supply. All states except Vermont currently require the use and retirement of NEPOOL Generation Information System (GIS) certificates, commonly referred to as Renewable Energy Certificates (RECs), to demonstrate compliance.[168]

To the extent that the price of renewable energy exceeds the market price of electric energy, LSEs incur a cost to meet the RPS target. That incremental unit

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[167] The cost ratios are often computed for transmission plant as a whole, and for distribution (or distribution net of services and meters) as a whole, although the ratios can also be disaggregated, as between substations and lines.

[168] Currently, Vermont's requirement will allow RECs to be sold off elsewhere (presumably for compliance in other states), therefore not leading to incremental renewable energy additions beyond what would be predicted in the presence of other states' requirements (although it has been argued that the Vermont requirements will support financing and therefore lead to more renewables being built, and therefore less reliance on Alternative Compliance Payments). We assume that by 2013, Vermont will adopt a binding RPS which requires the retirement of RECs for compliance, and thereby adds to the projection of total RPS additions. The year 2013 was chosen both because it is the year in which the current voluntary requirement would have become mandatory had the goals not been met, and because Vermont policy-makers are currently conducting an RPS study – the results of which are not likely to be implemented before 2013.

cost is the price of a REC. This annual compliance cost ($) equals the quantity of renewable energy purchased (kWh) multiplied by the REC price ($/kWh).

Energy-efficiency programs reduce the cost of compliance with RPS requirements by reducing the total load, or kWh, that must be supplied. Reduction in load due to DSM will reduce the RPS requirements of LSEs and therefore reduce the costs they seek to recover associated with complying with these requirements. The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices, multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. RPS targets for Connecticut, Maine, Massachusetts, New Hampshire and Rhode Island are based on state-specific legislation and regulation in effect as of April 2011. For Vermont, AESC 2011 assumes the adoption of an RPS, commencing in 2013 and requiring 5 percent eligible renewable energy by 2017, which is incremental to all goals previously described and which requires the retirement of RECs to demonstrate compliance.

This section forecasts those avoided RPS costs where the key input to the calculations is a forecast of the price of renewable energy in excess of market prices each year, i.e. the forecast price of RECs. This section presents a forecast of the expected future cost of renewable energy certificates and RPS compliance. We deduct the market price of energy from the forecast cost of renewable energy in order to calculate the forecast price of RECs for each RPS subcategory, by state and by year. For all Class 1 requirements, the forecasted price of RECs for the remainder of 2011 and all of 2012 is based on historic average broker quotations regarding short-term forward transactions consummated between January and April 2011. Beginning in 2019, Class 1 REC prices reflect the forecasted cost of new entry. Class 1 prices are interpolated for 2013 through 2018 by scrutinizing the expected balance between RPS-eligible supply and RPS demand and by including the expected impact of banked compliance[169]. For Class 2 requirements, the 2011 REC prices are based on a 12-month (May 2010 to April 2011) historic average of broker quotes and/or bid-ask spreads. These REC prices are summarized in Appendix C. Due to the differences in eligibility requirements among states, the supply and demand balance, and therefore the REC price, is expected to vary somewhat from state to state during this period. Beginning in

[169] In the event that an LSE purchases RECs in excess of its current year RPS obligation, each state allows LSEs to save and count that quantity of compliance against either of the following two compliance years. This compliance flexibility mechanism is referred to as banking. LSEs may only bank compliance within a single state, and may not transfer banked compliance credit to other entities.

2019, regional REC prices are expected to converge on the cost of new entry as all states rely on new or incremental renewable resources to meet their RPS demands.

6.5.1.1. New or Incremental Renewables Dominate Annual Additions to RPS Supply

New or *incremental* renewable resources are those that qualify as “Class I” in CT, MA, NH, ME, and as ‘new” in RI. AESC 2011 assumes that the anticipated VT RPS will include a Class 1 obligation with eligibility requirements substantially similar to those currently in effect in RI, and will therefore create incremental demand for new renewable energy. We refer to those categories in those states collectively as Class I. REC prices will be driven both by the costs of renewable resources eligible in each state <u>and</u> by the quantity of state-specific supply compared to state-specific demand. Because RPS eligibility criteria differ by state, REC prices continue to be differentiated by state until 2019 when regional REC prices are expected to converge because all states are relying on marginal resources to meet RPS demand.

In AESC 2011 we assume that the MA Solar Carve Out (a sub-set of MA Class I) reaches its 400 MW target in 2018 and that the target remains at this level through 2022. This is the proxy date for the point at which the last remaining "Opt-In Term" is expected to expire. Beginning in 2023, we assume that the Solar Carve-Out begins to sunset into MA Class I at the same rate as it ramped up, reaching zero carve-out shortly after the study period ends. Reductions in the installed cost of new solar facilities are assumed to drive SREC prices toward the $300 auction floor price from 2012 to 2018, with steeper declines in the early years. Beginning in 2019 (one year after the 400 MW target is reached) supply and demand dynamics may cause the market price of SRECs to drop below the auction floor price of $300, notwithstanding the fact that some SRECs are still eligible for the auction. MA DOER's SREC market structure is yet untested, and it is not clear whether an auction floor price will be able to be maintained once there is a substantial amount of supply in the market.

While Class I RPS requirements generally spur the development of new renewable resources, Class II, III and IV requirements are generally designed as “maintenance tiers.” These programs are intended to provide just enough financial incentive to keep the existing fleet of renewable resources in reliable operation. Due to their maintenance orientation, Class II, III and IV targets are generally held constant, with annual obligations varying only based on changes in the demand forecast. CT Class II, MA Class II-WTE, ME Class II, and RI "Existing" REC markets are in surplus. Therefore, REC prices in these markets are expected to remain relatively constant at levels just above the transaction cost. The MA Class II market has overlapping eligibility with CT Class I. In addition, while there is theoretically ample supply to meet MA Class II, fewer generators than expected have undertaken the steps necessary to comply with the eligibility criteria and become certified. Therefore, the MA Class II market is currently in shortage. In the long-run, MA Class II REC prices are assumed to be the lesser of CT Class I and 90% of the MA Class II Alternative Compliance Payment (ACP) rate. REC prices for MA APS are forecasted at 90% of the Alternative Compliance Payment (ACP) rate. The CT Class III market has an administratively-set REC price floor of $10. Based on the performance of this market to date, CT Class 3 compliance prices are expected to remain at $10 per MWh throughout the study period. Existing solar facilities across New England are eligible for NH Class II. As such, this market is expected to remain in balance, trend toward the MA Class I REC price between 2011 and 2014, and settle marginally above the MA Class I REC price for the remainder of the study period. The NH Class III and NH Class IV markets have overlapping eligibility with CT Class I. In the long-run, therefore, NH-III and NH-IV REC prices are assumed to be the lesser of CT Class I and 90% of their respective ACP rates.

Class I requirements will outpace the other classes on a GWh basis over time. This phenomenon is shown in Exhibit 6-46 that summarizes New England's total renewable energy requirements by year, based on the RPS targets by state and ISO-NE's 2011 CELT forecast, as discussed in Chapter 2. Exhibit 6-46 distinguishes between the quantity of Class I renewables that are required and the *aggregate* quantity of all other classes of renewables combined.

Exhibit 6-46: Summary of New England RPS Demand

New England Annual RPS Demand			
Year	Class 1 (GWh)	Other Classes (GWh)	Total (GWh)
2011	6,694	10,411	17,105
2012	8,066	10,607	18,673
2013	9,413	10,695	20,108
2014	10,785	10,810	21,595
2015	12,374	10,911	23,285
2016	13,990	11,013	25,003
2017	15,638	11,117	26,755
2018	17,126	11,224	28,350
2019	18,635	11,328	29,964
2020	20,034	11,435	31,469
2021	20,954	11,543	32,497
2022	21,893	11,652	33,545
2023	22,851	11,762	34,612
2024	23,827	11,873	35,700
2025	24,679	11,985	36,664
2026	25,547	12,098	37,645

Notes:
i. Class 1 includes voluntary demand.
Based on CELT 2011 and RPS targets summarized in Chapter 2.

The requirements for each RPS class were derived by multiplying the load of obligated entities (those retail LSEs subject to RPS requirements, often excluding public power) by the applicable annual class-specific RPS percentage target. The RPS requirements by class and year are listed in Appendix C. The load by state is based on CELT 2011 as detailed in Chapter 2.

The major sources of renewable supply forecast used to meet the RPS requirements by year are shown in Exhibit 6-47. These sources include wind, biomass, natural gas fuel cells, and hydro. The “other” category is included to represent the aggregate contribution of solar, landfill gas and tidal resources.

Exhibit 6-47: Cumulative Incremental Supply of Class 1 Renewable Energy Resources in New England, by Fuel Type (excludes resources already in the CELT Report)

Class 1 Renewable Energy Supply, by Fuel Type (GWh)						
Year	**Wind**	**Biomass**	**NGFC**	**Hydro**	**Other**	**Total**
	a	c	d	e	f	g = sum a to f
2012	71	47	67	50	388	**624**
2013	320	326	78	51	416	**1,192**
2014	2,419	1,005	93	55	466	**4,038**
2015	3,747	1,624	263	63	623	**6,320**
2016	4,515	2,014	310	68	678	**7,585**
2017	5,033	2,272	357	68	746	**8,476**
2018	5,107	2,272	404	68	805	**8,656**
2019	5,671	2,376	452	472	1,014	**9,984**
2020	6,532	2,381	499	472	1,014	**10,898**
2021	7,105	2,897	546	472	1,014	**12,034**
2022	7,765	2,897	594	472	1,014	**12,742**
2023	8,868	2,897	641	472	1,014	**13,891**
2024	9,321	3,051	688	472	1,015	**14,547**
2025	10,465	3,051	736	472	1,015	**15,739**
2026	10,988	3,051	783	472	1,015	**16,309**

Notes:
ii. Other includes solar, landfill gas & tidal
Based on Sustainable Energy Advantage, LLC proprietary database

The expected distribution of Class 1 RPS supplies between ISO-NE and adjacent control areas are summarized in Exhibit 6-48. Supply is categorized as follows:

- Existing eligible generation already operating (including biomass co-firing in existing facilities)
- The quantity of (energy and) RECs currently imported from RPS-eligible facilities located outside of ISO-NE
- The assumed incremental level of (energy and) RECs imported from RPS-eligible facilities located outside of ISO-NE
- The assumed incremental renewable resources by fuel type.

Exhibit 6-48: Expected Distribution of New Renewable Energy between ISO-NE and Adjacent Control Areas

	Class 1 RPS Supply					New RE Demand	
	ISO-NE Supply		Imported Supply				
Year	Operating	Incremental	Current	Expected	TOTAL	New Renewable Requirement GWh	New Renewable Energy Surplus/(Shortage)
	a	b	c	d	e = sum a to d	f	g = e-f
2012	5,803	118	1,814	656	**8,391**	**8,066**	324
2013	5,803	661	1,767	1,067	**9,298**	**9,413**	(115)
2014	5,803	3,476	1,754	1,465	**12,498**	**10,785**	1,713
2015	5,803	5,540	1,741	1,843	**14,927**	**12,374**	2,554
2016	5,803	6,723	1,728	2,220	**16,474**	**13,990**	2,484
2017	5,803	7,500	1,716	2,596	**17,614**	**15,638**	1,976
2018	5,803	7,573	1,703	2,972	**18,051**	**17,126**	925
2019	5,803	8,854	1,691	3,348	**19,695**	**18,635**	1,060
2020	5,803	9,720	1,678	3,724	**20,926**	**20,034**	892
2021	5,803	10,809	1,666	3,720	**21,998**	**20,954**	1,044
2022	5,803	11,469	1,654	3,716	**22,642**	**21,893**	749
2023	5,803	12,572	1,642	3,712	**23,728**	**22,851**	878
2024	5,803	13,179	1,629	3,708	**24,319**	**23,827**	492
2025	5,803	14,323	1,618	3,704	**25,448**	**24,679**	769
2026	5,803	14,846	1,606	3,700	**25,955**	**25,547**	407

Exhibit 6-48 also compares total Class I RPS supply to total new renewable energy demand. The combination of operating supply, projects currently under development, and resource potential from the renewable energy supply curve analysis are expected to keep supply and demand in balance through 2026.

Over time, the net requirements met by resources within ISO-New England will be further reduced by an estimate of *additional* RPS-eligible imports over existing tie lines, phased in at a rate consistent with the recent historical rate of increase in RPS-eligible imports over a ten-year period.

In addition to *new* or *incremental* renewables, several states also have minimum requirements for existing renewable energy sources, or other eligible sources. The eligibility details and target percentages are summarized in Appendix C.

6.5.1.2. Estimated Cost of Entry for New or Incremental Renewable Energy

Our general approach to estimating renewable supply is described in Chapter 2. We assume that in the long-run, the price of renewable energy certificates (and therefore the unit cost of RPS compliance) will be determined by the cost of new entry of the marginal renewable energy unit. To estimate the new or incremental REC cost of entry, we constructed a supply curve for incremental New England renewable energy potential based on various resource potential studies that sorts the supply resources from the lowest cost of entry to the highest cost of entry.[170] The resources in the supply curve model are represented by 135 blocks of supply potential from resource studies, each with total MW capacity, capacity factor, and cost of installation and operation applicable to projects installed in each year.

The supply curve consists of land-based wind, biomass, hydro, landfill gas, offshore wind and tidal resources. Land-based wind is the largest source by far, modeled as 86 blocks, varying by state, number and size of turbines in each project, wind speed and distance from transmission.

The price for each block of the supply curve is estimated for each year. For each generator, we determine the levelized REC premium, or additional revenue the project would require to attract financing, for market entry by subtracting the nominal levelized value of production consistent with the AESC 2011 projection of wholesale electric energy prices from the nominal levelized cost of marginal resources:[171]

- The nominal levelized cost of marginal resources is the amount the project needs in revenue on a levelized $/MWh basis;
- The nominal levelized value of production is the amount the project would receive from selling its commodities (energy, capacity, ancillary services) into the various wholesale markets; and
- The difference between the levelized cost and the levelized value represents the REC premium.

Unless the revenue from REC prices can make up the REC premium, a project is unlikely to be developed. Resource blocks are sorted from low to high REC price, and the intersection between incremental supply and incremental demand determines the market-clearing REC price for market entry. Our projections assume that REC prices for new renewables will not fall below $2/MWh, which is the estimated transaction cost associated with selling renewable resources into the

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[170] These assumptions are based on technology assumptions compiled by Sustainable Energy Advantage, LLC from a range of studies and interviews with market participants. Some characteristics are adapted from those used in a New England renewable energy supply curve analysis prepared by Sustainable Energy Advantage, LaCapra Associates and AWS Truewind for the Maine Governors Wind Task Force Study on behalf of the Natural Resources Council of Maine. Typical generator sizes, heat rates, availability and emission rates are consistent with technology assumptions used by ISO-New England in its scenario planning process. The resulting supply curve is proprietary to Sustainable Energy Advantage, LLC.

[171] SEA calculated these levelized analyses using discount rates representative of the cost of capital to a developer of renewable resource projects.

wholesale energy market. This estimate is consistent with market floor prices observed in various markets for renewable resources.

The estimated levelized cost of marginal resources is based on several key assumptions, including projections of capital costs, capital structure, debt terms, required minimum equity returns, and depreciation, which are combined and represented through a carrying charge. The estimated levelized cost of marginal resources also includes fixed and variable operations and maintenance costs, transmission and interconnection costs (as a function of voltage and distance from transmission), and wind integration[172] costs. The Federal Production Tax Credit is assumed to be phased out over a seven year period following 2013. Capital and operating costs were escalated over time using inflation.

The levelized commodity revenue over the life of each resource was determined based on the sum of energy and capacity prices, both utilizing preliminary AESC 2011 reference-case estimates of the FCM price and all-hour zonal LMP.

Revenues for wind resources were adjusted in three ways:

- The value of wind energy was adjusted to reflect wind's variability, production profile, and historical discount of the real-time market (in which wind plants will likely sell a significant portion of their output) versus the day-ahead market.
- Energy prices were further discounted to reflect the lower prices typical in long-term contracts, especially for wind plants, with their fluctuating energy output.[173]
- Wind generators were assumed to receive FCM revenues corresponding to only 15% of nameplate capacity, reflecting the poor performance of most on-shore wind plants on summer afternoons. This assumption may be conservative for commercial wind farms, reflecting developer, investor and lender risk-aversion regarding future capacity valuation.

Resources from the supply curve are modeled to meet net demand (as described earlier), which consists of the gross demand for new or incremental renewables, less:

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[172]We assume that reinforcement of major transmission facilities (e.g., improved connections between Maine and the rest of New England) will be socialized.

[173]Our forecast of REC prices assumes that most renewables will be financed with long-term contracts for most of their capacity and/or RECs.

a) Existing eligible generation already operating (including biomass co-firing in existing facilities);

b) The current level of RPS imports; and

c) Additional imports over existing ties to neighboring control areas.

In addition, for solar and fuel-cell resources, which tend not to be resource-constrained, we separately estimated the amounts that would be driven by various policy initiatives; these amounts were also netted from gross demand.

As previously stated, 2011 and 2012 REC prices were estimated using broker quotes. Due to the scale of expected surpluses in the near-term (which derive from new supply that has come on-line since our analysis for AESC 2009, and an increase in renewable energy imports), as well as the ability to bank RPS compliance, the cost of new entry is not expected to be determined by generic supply curve supply until roughly 2019. Until then, REC prices are estimated by scrutinizing the expected balance between RPS-eligible supply and RPS demand and by including the expected impact of banked compliance. Beginning in 2019, regional REC prices are expected to converge on the cost of new entry as all states rely on new or incremental renewable resources to meet their RPS demands. Our projection of the cost of new entry is summarized in Exhibit 6-49.

Exhibit 6-49: REC Premium for Market Entry ($/MWh)

REC Premium for Market Entry	
Year	(2011 $/MWh)
2019	$5.14
2020	$6.63
2021	$3.46
2022	$6.84
2023	$9.82
2024	$10.23
2025	$7.85
2026	$4.12

These results are highly dependent upon the forecast of wholesale electric energy market prices, including the underlying forecasts of natural gas and carbon allowance prices, as well as the forecast of inflation. A lower forecast of market energy prices would yield higher REC prices than shown, particularly in the long term. This phenomenon is demonstrated when comparing the long-run REC prices in the AESC 2011 with those from the AESC 2009 study. In the intervening period RPS supply has caught up with and surpassed RPS demand. REC prices are comparable between the two studies during the years of expected equilibrium, and then REC prices based on the cost of new entry in AESC 2011 are lower than those forecasted in AESC 2009 based primarily on the fact that equipment and raw material prices have come down from their artificial peaks of 2008 and 2009. In all cases, project developers will need to be able to secure long-term contracts and attract financing based on the aforementioned natural gas, carbon and resulting electricity price forecasts in order to create this expected REC market environment. This presents an important caveat to the projected REC prices, as such long-term electricity price forecasts (particularly to the extent that they are influenced by expected carbon regulation) are not easily taken to the bank.

In contrast to the long-term REC cost of entry, spot prices in the near term will be driven by supply and demand, but are also influenced by REC market dynamics and to a lesser extent to the expected cost of entry (through banking), as follows:

- Market shortage: Prices approach the cap or Alternative Compliance Payment
- Substantial market surplus, or even modest market surplus without banking: Prices crash to approximately \$0.50 to \$2/MWh, reflecting transaction and risk management costs
- Market surplus with banking: prices tend towards the cost of entry, discounted by factors including the time-value of money, the amount of banking that has taken place, expectations of when the market will return to equilibrium, and other risk management factors.

Detailed projections of REC prices by state for Class I renewables are presented in Appendix C.

6.5.1.3. Avoided RPS Compliance Cost per MWh Reduction

The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

$$\frac{\sum_{\mathrm{n}} \mathrm{P}_{\mathrm{n,i}} \times R_{n,i}}{1-l}$$

Where:

i = year

n = RPS classes

$P_{n,i}$ = projected price of RECs for RPS class n in year i,

$R_{n,i}$ = RPS requirement for RPS class n in year i, from Exhibit 3-9 in Deliverable 3-1.

l = losses from ISO wholesale load accounts to retail meters

For example, in a year in which REC prices are $30/MWh and the RPS percentage is 10%, the avoided RPS cost to a retail customer would be $30 × 10% = $3/MWh. Detailed results from Appendix C are incorporated into the Appendix B Avoided Cost Worksheets by costing period. The year-by-year RPS percentages for each RPS tier are shown in Appendix C.

The levelized RPS price impact for the 2012 to 2026 period, in 2011$ per MWh of load, is shown below:

Exhibit 6-50: Levelized RPS Price Impact (2012-2026)

Avoided RPS Cost by Class ($/MWh of Load) Levelized Price Impact 2012 – 2026 (2011$)						
	CT	ME	MA	NH	RI	VT
Class I	$1.77	$0.87	$1.74	$1.31	$1.41	$0.50
All Other Classes	$0.40	$0.05	$3.24	$0.99	$0.01	$0.00
Total	**$2.17**	**$0.92**	**$4.98**	**$2.30**	**$1.43**	**$0.50**

6.6. Externalities

Externalities are impacts from the production of a good or service that **are not** reflected in price of that good or service, and that are **not** considered in the decision to provide that good or service.[174] Air pollution is a classic example of an externality, as pollutants released from a facility impose health impacts on a population, cause damage to the environment, or both. The costs of those health impacts and ecosystem damages are not reflected in the price of the product and are generally not borne by the owner of the pollutant source. These costs are thus external to the financial decisions pertaining to the source of the pollutant. Therefore, externalities equal the total value of the adverse impacts minus the value of those impacts reflected in market prices.

In Chapter 2, we identify the impacts of pollutants that **are** reflected in market

[174] In economics, an externality can be positive or negative; in this discussion we are focusing on negative externalities.

prices in New England. There are many significant air pollutants associated with electric generation, but NO_x, SO_x, and CO_2 are the three primary pollutants that are currently subject to federal and/or state or regional regulation. Our electric market simulation model incorporates assumptions regarding compliance costs for those emissions as part of its estimation of the market price of electricity. The simulation model includes these costs when calculating bid prices and making commitment and dispatch decisions.

The Scope of Work for AESC 2011 asks for the heat rates, fuel sources, and emissions of NO_x, and CO_2 of the marginal units during each of the energy and capacity costing periods in the 2011 base year. It also asks for the quantity of environmental benefits that would correspond to energy efficiency and demand reductions, in pounds per MWh, respectively, during each costing period.

Exhibit 6-51 and Exhibit 6-52 summarizes the marginal heat rate and marginal fuel characteristics from the model results. The results of the two exhibits are based on the marginal unit in each hour in each transmission area, as reported by the model. Once the marginal units are identified, we extracted the heat rates, fuel sources, and emission rates for the key pollutants from the database of input assumptions used in our Market Analytics simulation of the New England wholesale electricity market.

Exhibit 6-51: 2011 New England Marginal Heat Rate by Pricing Period (Btu per kWh)

	Season and Period				
	Summer		**Winter**		**Grand Total**
	Off Peak	On Peak	Off Peak	On Peak	
Average Heat Rate (BTU/kWh)	9,543	10,188	9,161	8,494	**9,183**

Exhibit 6-52: 2011 New England Marginal Fuel Type

	Season and Period				
	Summer		Winter		
Fuel Type	Off Peak	On Peak	Off Peak	On Peak	**Grand Total**
Natural gas	70%	68%	64%	83%	**71%**
Oil	0%	1%	1%	1%	**1%**
Coal	24%	29%	24%	15%	**22%**
Nuclear	5%	1%	11%	1%	**5%**
Biomass	1%	1%	0%	0%	**0%**
Other	0%	0%	0%	0%	**0%**
Renewable	0%	0%	0%	0%	**0%**
Grand Total	**100%**	**100%**	**100%**	**100%**	100%

Our discussion of the methodology that we employ is discussed below:

We calculate the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of pounds per MWh. We do this by multiplying the quantity of fuel burned by each marginal unit by the corresponding emission rate for each pollutant for that type of unit and fuel.

The calculations for each pollutant in each hour are as follows:

$$\text{Marginal Emissions} = [\text{Fuel Burned}_{MU}\ (\text{MMBtu}) \times \text{Emission Rate}_{MU}\ (\text{lbs/MMBtu}) \times 1\ \text{ton}/2000\ \text{lbs}]/\text{Generation}_{MU}\ (\text{MWh})$$

Where:

$Fuel\ Burned_{MU}$ = the fuel burned by the marginal unit in the hour in which that unit is on the margin,

$Emission\ Rate_{MU}$ = the emission rate for the marginal unit, and

$Generation_{MU}$ = generation by the marginal unit in the hour in which that unit is on the margin.

The avoided emissions values shown in the exhibits below represent the averages for each pollutant over each costing period for all of New England in pounds per MWh. The emission rates are presented by modeling zone, however differences between zones tend to be relatively insignificant.

Exhibit 6-53: 2011 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (lbs/MWh)

CO2 (lbs/MWh)	Summer		Winter		
Transarea	Off Peak	On Peak	Off Peak	On Peak	**Grand Total**
NE - Boston	1,211	1,330	1,140	1,079	**1,163**
NE - CT Central-Northeast	1,240	1,346	1,146	1,090	**1,176**
NE - CT Norwalk	1,240	1,347	1,148	1,090	**1,177**
NE - Northeast MA	1,240	1,347	1,148	1,090	**1,177**
NE - New Hampshire	1,225	1,341	1,136	1,082	**1,167**
NE - Rhode Island	1,230	1,354	1,148	1,070	**1,170**
NE - Southeast MA	1,216	1,336	1,130	1,072	**1,159**
NE - Vermont	1,216	1,335	1,131	1,072	**1,159**
NE - West Central MA	1,230	1,347	1,143	1,086	**1,172**
NE - CT Southwest	1,229	1,350	1,143	1,090	**1,174**
NE - Maine	1,201	1,306	1,133	1,005	**1,132**
Average	**1,225**	**1,340**	**1,140**	**1,075**	**1,166**

Exhibit 6-54: 2011 New England Avoided NOx Emissions by Modeling Zone and Pricing Period (lbs/MWh)

NOx (lbs/MWh)	Summer		Winter		
Transarea	Off Peak	On Peak	Off Peak	On Peak	**Grand Total**
NE - Boston	0.646	1.076	0.635	0.477	**0.708**
NE - CT Central-Northeast	0.762	1.081	0.656	0.513	**0.753**
NE - CT Norwalk	0.757	1.084	0.656	0.514	**0.753**
NE - Northeast MA	0.708	1.094	0.640	0.491	**0.733**
NE - New Hampshire	0.698	1.100	0.647	0.452	**0.724**
NE - Rhode Island	0.664	1.083	0.634	0.461	**0.711**
NE - Southeast MA	0.664	1.083	0.634	0.461	**0.711**
NE - Vermont	0.716	1.092	0.654	0.495	**0.739**
NE - West Central MA	0.729	1.101	0.654	0.506	**0.747**
NE - CT Southwest	0.757	1.084	0.656	0.514	**0.753**
NE - Maine	0.663	1.041	0.727	0.429	**0.715**
Average	**0.706**	**1.084**	**0.654**	**0.483**	0.732

In this 2011 AESC report, we find that CO_2 has the most significant externality. We also conclude that the long-run marginal abatement cost of CO_2 is a practical and conservative measure of the full cost of carbon. In updating our recommendation from the 2009 AESC report, we review current literature on emissions reductions necessary to avoid the most dangerous impacts of climate change, as well as analyses of technologies available to achieve those emission reductions. We recommend that the Study Group uses a marginal abatement cost value which is based on the cost of controlling emissions.[175]

For AESC 2011, we recommend using a long-run marginal abatement cost (2011$) of $80 per short ton of CO_2. This is effectively a slight reduction in real dollars from our recommendation in AESC 2009 of $80 per short ton in 2009$ ($81.52 in 2011$). This estimate is still one-third higher than the value of $63 (2011$) per short ton recommended in AESC 2007. In 2011 approximately two percent of the $80 per ton is internalized in the market price of electricity, through RGGI, and 98 percent is an externality. By 2026, we estimate that approximately 49 percent of that amount will be internalized.

[175] This is an alternative to setting value based on monetized estimates of damages.

6.6.1. History of Environmental Externalities: Policies in New England

In the 1990's several New England states had proceedings dealing with externalities that influence current utility planning and decision-making.[176] In Massachusetts, dockets DPU 89-239 and 91-131 served as models for other states. Docket DPU 89-239 was opened to develop "Rules to Implement Integrated Resource Planning" and included consideration of many aspects of IRP including determination and application of environmental externalities values. This docket adopted a set of dollar values for air emissions, including a CO_2 value of $22 per ton of CO_2 (in 1989 dollars) (Exhibit DOER-3, Exhibit. BB-2, p. 26). Docket DPU 91-131 examined environmental externalities to develop recommendations of various approaches for quantifying the CO_2 externality value. The Department's Order in Docket DPU 91-131 was noteworthy for its foresight regarding climate change, albeit optimistic about the timing of recognition of climate change into policies and regulation in the United States.[177] Based on information in the record, the Department reaffirmed the CO_2 value it had adopted in the previous case, $22 per ton (in 1989 dollars).

6.6.2. Carbon Dioxide

Externalities associated with electricity production and uses include a wide variety of air pollutants, water pollutants, and land use impacts. The list of externalities from energy production and use is quite long, and includes the following:

- Air emissions (including SO_2, NO_x and ozone, particulates, mercury, lead, other toxins, and greenhouse gases) and the associated health and ecological damages;
- Fuel cycle impacts associated with "front end" activities such as mining and transportation, and waste disposal;
- Water use and pollution;
- Land use;
- Aesthetic impacts of power plants and related facilities;
- Radiological exposures related to nuclear power plant fuel supply and operation (routine and accident scenarios);

[176] A more detailed description of the history of electricity generation environmental externalities and policies in New England may be found in AESC 2007 (p. 7-6–7-8).

[177] AESC 2009 provides more detail about the Massachusetts DPU Order in Docket DPU 91-131.

- Other non-environmental externalities such as economic impacts (generally focused on employment), energy security, and others.

Many of these externalities have been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of those costs in their production and use decisions, thereby "internalizing" a portion of those costs.[178]

We anticipate that the "carbon externality" will continue to be the dominant externality associated with marginal electricity generation in New England. This is the case for two main reasons. First, regulations to address the greenhouse gas emissions responsible for global climate change have yet to be adopted with sufficient stringency to link scientific research and evidence with long-term policy that would enable carbon-free resources to replace fossil-based generation lag, particularly in the United States.[179] The damages from the EPA's Criteria air pollutants are relatively bounded, and to a great extent "internalized," as a result of existing regulations. In contrast, global climate change is a problem on an unprecedented scale with far-reaching and potentially catastrophic implications.

Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal SO_2, mercury, and particulate emissions, as well as relatively low NO_x emissions.

Based on knowledge of the electric system and review of model runs, it is believed that the dominant environmental externality in New England over the study period will be the un-internalized cost of carbon dioxide emissions. The current RGGI

[178] For example, the Clean Air Transport Rule, while currently in draft form, is expected to adjust the SO_2 and NO_x emissions caps downward with an ultimate effect of reducing SO_2 emissions approximately 73 percent from 2003 levels. Under the draft rule, annual emissions of SO_2 are required to decline from 4.7 million tons in 2009 to 3.9 million tons by 2012, and then to 2.5 million tons by 2014, for a cumulative reduction of 47 percent over the five-year compliance period. Annual NO_x emissions are capped at 1.4 million tons. As a result, while there will be some "external costs" associated with the residual SO_2 and NO_x pollution, these externalities are now relatively small. The EPA's proposed Air Toxics Rule governing electric utilities under section 112(d) of the Clean Air Act would do the same for emissions of mercury and other air toxics, while the proposed rule under section 316(b) of the Clean Water Act would minimize the externalities associated with the impingement and entrainment of aquatic organisms from power plant cooling water intake systems.

[179] On April 17, 2009; EPA issued a proposed finding that concluded that greenhouse gases posed an endangerment to public health and welfare under the Clean Air Act ("Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" 74 Fed. Register 78: 18886–18910). This proposed finding initiates the process of potentially regulating greenhouse gases as an air pollutant. http://epa.gov/climatechange/endangerment.html

auctions and any federal CO_2 regulations only internalize a portion of the "greenhouse gas externality," particularly in the near term. Values were developed for the one major emission associated with avoided electricity costs for which the near-term internalized cost most significantly understates the value supported by current science.

6.6.3. General Approaches to Monetizing Environmental Externalities

There are various methods available for monetizing environmental externalities such as air pollution from power plants. These include various "damage costing" approaches that seek to value the damages associated with a particular externality, and various "control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant (thus internalizing a portion or all of the externality).

The "damage costing" methods generally rely on travel costs, hedonic pricing, and contingent valuation in the absence of market prices. These are forms of "implied" valuation, asking complex and hypothetical survey questions, or extrapolating from observed behavior. For example, data on how much people will spend on travel, subsistence, and equipment, can be used to measure the value of those fish, or more accurately the value of *not* killing fish via air or water pollution. Human lives are sometimes valued based upon wage differentials for jobs that expose workers to different risks of mortality. In other words, comparing two jobs – one with higher hourly pay rate and higher risk than the other – can serve as a measure of the compensation that someone is "willing to accept" in order to be exposed to the risk.

There are myriad problems with these approaches, two of which will be discussed here. The damage costing approaches are, in the case of global climate change, simply subject to too many problematic assumptions. We do not subscribe to the view that a reasonable economic estimate of the "damages" around the world can be developed and used as a figure for the externalities associated with carbon dioxide emissions. In other words, estimating damage is a moving target–it depends upon what concentrations we ultimately reach (or what concentrations we reach and then reduce). This is exacerbated by the fact that we do not fully understand what changes in the earth's climate might occur assuming carbon dioxide concentrations continue to increase past the current 380 parts per million, toward a projected 450 parts per million (or even higher) climate change, and cannot project with certainty the levels at which certain impacts will occur.

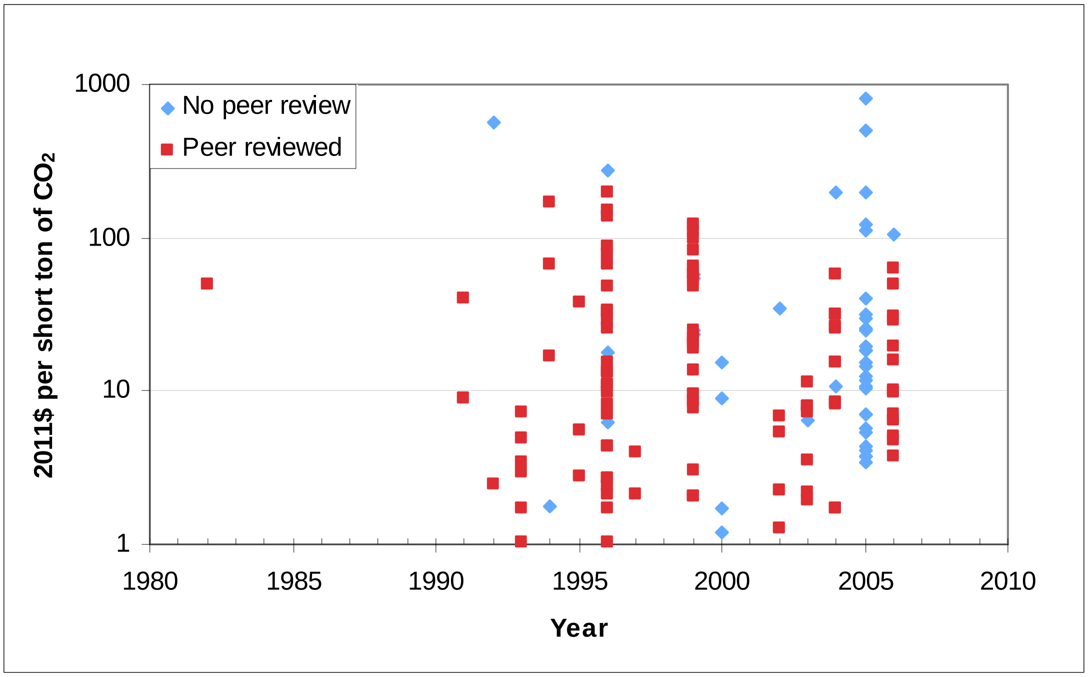
A further complicating factor is that different emissions concentrations create different damages for different regions and different groups of people. Estimating damages is fraught with difficulties including: (a) identifying the categories of changes to ecosystems and societies around the planet; (b) estimating magnitudes of impacts; (c) valuing those impacts in economic terms; (d) aggregating those values across countries with different currency exchange rates and different cultures; (e) addressing the non-linear and catastrophic aspects of the climate change damage; and (f) dealing with the paradoxes and conundrums involved in applying financial discount rates to effects stretching over centuries.

These difficulties are evident when examining various existing damage estimates. A meta-study from 2008 by author Richard Tol compares 211 estimates of this "social cost of carbon," which represents the economic costs of the damages from climate change aggregated across the globe and discounted to the present.[180] These estimates come from 47 studies done between 1982 and 2006.[181] The figure below shows a scatter plot of these estimates over time. The social cost of carbon is shown on the vertical axis, expressed in 2011 dollars per short ton of CO_2. Due to the wide range of the distribution, this value is expressed in log terms. The year of the study is shown on the horizontal axis. These studies use different methodologies, discount rates, damage functions, physical impacts of climate change, and equity weightings across individuals in different parts of the world, all of which are reflected in the resulting damage cost estimates. Hence, estimates vary across time and no particular pattern emerges when examined together.

[180] Tol, Richard S.J. *The Social cost of Carbon: Trends, Outliers and* Catastrophes. Economics E-Journal. Vol 2, 2008-25. August 12, 2008.

[181] It should be noted that many of the studies included in the meta-analysis were authored or co-authored by Richard Tol.

Exhibit 6-55: Scatter Plot of Converted Values of Tol 2009 Societal Cost of Carbon



Conversely, the "control cost" methods generally look at the *marginal* cost of control. That is, the cost of control valuations look at the last (or most expensive) unit of emissions reduction required to comply with regulations. The cost of control approach can be based upon a "regulators' revealed preference" concept. That is, if "air regulators" are requiring a particular technology with a cost per ton of $X to be installed at power plants, then this can be taken as an indication that the value of those reductions is perceived to be at or above the cost of the controls. The fact that the "regulators' revealed preferences" approach is unavailable, as regulators have not established relevant reference points, complicates the task of determining a carbon externality cost. The cost of control approach can also be based upon a "sustainability target" concept. With the sustainability target, we start with a level of damage or risk that is considered to be acceptable, and then estimate the marginal cost of achieving that target. It is important to note that, at this stage in our collective understanding of the science of climate change, as well as its social, economic, and physical impacts, the notion of a "sustainability target" is a construct useful for discussion, but not yet firmly established.

The "sustainability target" approach relies on the assumption that the nations of the world will not tolerate unlimited damages. It also relies partly on an expectation that policy leaders will realize that it is cheaper to reduce emissions now and achieve a sustainability target than it is not to address climate change. It is worth noting that a cost estimate based on a sustainability target will be a bit lower than a damage cost estimate because the "sustainability target" is going to be a calculus of what climate change the planet is already committed to, and what additional change we are willing to live with (again complicated by the fact that different regions will see different impacts, and have different ideas about what is dangerous and what is sustainable).

6.6.4. Estimation of CO_2 Environmental Costs

Based upon our review of the merits of those various approaches, we selected an approach that estimates the cost of controlling, or stabilizing, global carbon emissions at a "sustainable level" or sustainability target. To develop that estimate, the most recent science regarding the level of emissions that would be sustainable was reviewed, as well as the literature on costs of controlling emissions at that level.

The conceptual and practical challenges for estimating a carbon externality price include the following:

- The damages are very widely distributed in time (over many decades or even centuries) and space (across the globe);
- The "physical damages" include some impacts that are very difficult to quantify and value, such as flooding large land areas; changes to local climates; species range migration; increased risk of flood and drought; changes in the amount, intensity, frequency, and type of precipitation; changes in the type, frequency, and intensity of extreme weather events (such as hurricanes, heat waves, and heavy precipitation);
- This list of "physical damages" includes some that are extremely difficult, perhaps impossible, to reasonably express in monetary terms;
- The scientific understanding of the climate change process and climate change impacts is evolving rapidly;
- There may well be reasons (not considered here) that the environmental cost value could have a shape that starts lower and increases faster, or vice versa, having to do with periods in which rates of change are most problematic;
- The scale of the impact on the world economies associated with the impacts of climate change and/or associated with the transformations of economies to reduce greenhouse gas emissions are so large that using terms and concepts such as "marginal" can be problematic; and

The impacts of climate change are non-linear and non-continuous, including "feedback cycles" that can most reasonably be thought of in terms of thresholds beyond which there are “run away damages” such as irreversible melting of the Greenland ice sheet and the West Antarctic ice sheet, and collapse of the Atlantic thermohaline circulation—a global ocean current system that circulates warm surface waters.

Given the daunting challenge of valuing climate damages in economic terms, we propose taking a practical approach consistent with the concepts of “sustainability” and “avoidance of undue risk.” Specifically, the carbon externality can be valued by looking at the marginal costs associated with controlling total carbon emissions at, or below, the levels that avoid the major climate change risks according to current expectations.

Nonetheless, because the environmental costs of energy production and use are so significant, and because the climate change impacts associated with power plant carbon dioxide emissions are urgently important, it is worthwhile to attempt to estimate the externality price and to put it in dollar terms that can be incorporated into electric system planning.

6.6.4.1. What is Current Understanding of the Correct Level of CO_2 Emissions?

In order to determine what is currently deemed a reasonable sustainability target, we reviewed current science and predicted policy impacts that have been released since AESC 2009.

We reviewed several sources to determine reasonable assumptions about what level of concentrations are deemed likely to achieve the sustainability target and what emission reductions are necessary to reach those emissions levels. The Intergovernmental Panel on Climate Change’s most recent Assessment Report (IPCC 2007a, 15) indicates that concentrations of 445 to 490 ppm CO_2 equivalent correspond to 2^o to 2.4^oC increases above pre-industrial levels. A comprehensive assessment of the economics of climate change, Stern (2007) proposes a long-term goal to stabilize greenhouse gases at between the equivalent of 450 and 550 ppm CO_2. Recent research indicates that achieving the 2^oC goal likely requires stabilizing atmospheric concentrations of carbon dioxide and other heat-trapping gases near 400 ppm carbon dioxide equivalent (Meinshausen 2006).

The Intergovernmental Panel on Climate Change (IPCC 2007, Table SPM5) indicates that reaching concentrations of 450 to 490 ppm CO_2 equivalent requires reduction in global CO_2 emissions in 2050 of 50 to 85 percent below 2000 emissions levels. Stern (2007, xi) says that global emissions would have to be 70 percent below current levels by 2050 for stabilization at 450 ppm CO_2 equivalent. To accomplish such stabilization, the United States and other industrialized countries would have to reduce greenhouse gas emissions on the order of 80 to 90 percent below 1990 levels, and developing countries would have to achieve reductions from their baseline trajectory as soon as possible (den Elzen and Meinshausen, 2006).

In the United States, several states have adopted state greenhouse gas reduction targets of 50 percent or more reduction from a baseline of 1990 levels or then-current levels by 2050 (California, Connecticut, Illinois, Maine, New Hampshire, New Jersey, Oregon, and Vermont). The state of Massachusetts has set targets for even greater reductions of greenhouse gases. The Global Warming Solutions Act (GWSA) was signed into law by Governor Deval Patrick in August 2008. The Act calls for initial reductions in greenhouse gas emissions of between 10 percent and 25 percent below 1990 levels by 2020. In the *Massachusetts Clean Energy and Climate Plan for 2020*, released on December 29, 2010 by the Massachusetts Executive Office of Energy and Environmental Affairs, the reduction target was set at 25 percent below 1990 levels. The Global Warming Solutions Act also has emissions reduction targets for 2030 and 2040, leading to an emissions reductions target of 80 percent below 1990 levels by 2050.

6.6.4.2. Cost of Stabilizing CO_2 Emissions

There have been several efforts to estimate the costs of achieving a variety of atmospheric concentration targets. The most comprehensive effort is the work of the Intergovernmental Panel on Climate Change. The IPCC was established by the World Meteorological Organization and UNEP in 1988 to provide scientific, technical and methodological support and analysis on climate change. IPCC has issued four assessment reports on the science of climate change, climate change impacts, and on mitigation and adaptation strategies (in 1990, 1995, 2001, 2007). The IPCC's Fifth Assessment Report is due in 2014.

IPCC (2007a) indicates that reductions on the order of 34 gigatons would be necessary to achieve an 80 percent reduction below current emission levels. [182] IPCC (2007b, p. 45) estimates that up to 31 gigatons in reductions are available for \$98 per short ton of CO_2 or less (Working Group III Summary for Policy Makers) in 2011 dollars.[183]

For the 2011 AESC, we have examined other more recent studies, produced since July 2009, on the costs of achieving stabilization targets that include the following, and converted the given values to 2011\$ per short ton of CO_2:

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[182] 2000 emissions levels were 43Gt CO_2-eq. IPCC (2007a).

[183] This value, expressed in Table TS.3 in 2006 dollars per metric ton, is \$97 per short ton of CO_2 in 2011 dollars (\$100 metric ton of $CO_2 \times 1.07$ [2006 to 2011 GDP values] × (1 metric ton/1.102 short ton)).

- In 2010 McKinsey and Company (McKinsey 2010) released an update to its second version of the Global Greenhouse Gas Abatement Cost Curve[184] in order to examine the impacts of the global financial crisis on carbon economics and emissions reductions.[185] The analysis came to the conclusion that the global financial crisis and resulting economic downturn has had a small impact on long-term emissions, and thus the size of the required emission reductions remains essentially the same. A stabilization level of 550 ppm, consistent with a temperature increase of 3°C, would result in a marginal abatement cost of $101 per short ton of CO_2. McKinsey increased its estimate from $75 per short ton in 2009 in order to include known carbon capture and storage (CCS) controls. The amount of energy necessary to run CCS controls leads to increases in the CO_2 abatement cost. Achieving a stabilization level of 450 ppm, consistent with a temperature increase of 2°C, would result in a marginal abatement cost of $126 per short ton.[186]
- In the World Energy Outlook 2010, the International Energy Agency (IEA 2010a) has modeled the implications and results of three international policy framework scenarios: (1) the Current Policies Scenario, in which country CO_2 policies are held constant as of mid-2010; (2) the New Policies Scenario, which takes into account broad policy commitments and plans that countries have announced but not yet implemented; and (3) the 450 Scenario, which stabilizes CO_2 levels at 450 ppm to limit temperature increase to 2°C. Under the Current Policies Scenario, the IEA projects carbon prices of $46 per short ton of CO_2 in 2035, and a price of $39 per short ton under the New Policies Scenario. Prices under the 450 Scenario are projected to be $111 per short ton for OECD+ countries and $83 per short ton for Other Major Economies. [187]

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[184] The original Global Greenhouse Gas Abatement Cost Curve was released in 2007. The second version was released in 2009. The 2010 update is known as Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.

[185] McKinsey and Company did not update technology projections, but rather focused on updating the macroeconomic effects on emissions in the business-as-usual (BAU) scenario, and the resulting impact on emission reduction economics. A small number of model upgrades and enhancements were also performed.

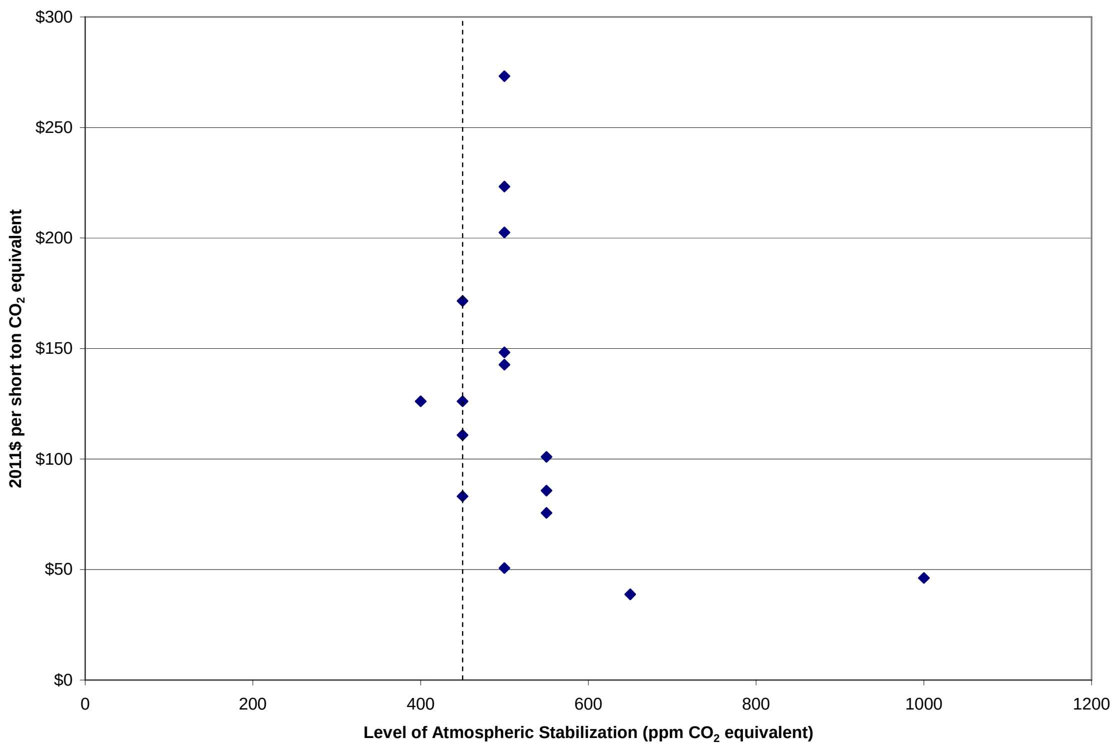
[186] The report values are expressed in 2005 Euros per metric ton of CO_2 of 80 and 100 Euros respectively.

[187] OECD+ countries include all OECD countries, as well as non-OECD countries in the European Union. Other Major Economies includes Brazil, China, the Middle East, Russia, and South Africa.

- The IEA examines four policy scenarios in its Technology Perspectives 2010, all of which reduce emissions of CO_2 by 50 percent from 2005 levels by 2050. In the Blue Map Scenario, these targets are achieved at a cost of $163 per short ton. If carbon capture and sequestration technologies are not available, the marginal cost of abatement increases to $273 per short ton. In the Blue Map case with high amounts of nuclear power, abatement cost is $148 per short ton. Finally, in the Blue Map case with high renewables, controls costs are $142 per short ton.

The results of these studies mentioned above, as well as additional studies by the same entities[188], are summarized in Exhibit 6-56. The dotted line is drawn at the value of atmospheric stabilization of 450 ppm CO_2 equivalent, which corresponds to a global temperature increase of 2°C above pre-industrial levels.

Exhibit 6-56: Summary Chart of Marginal Abatement Cost Studies



188 These additional studies include: (1) McKinsey & Company. 2009. "Pathways to a Low-Carbon Economy: Version 2 of the Global Greenhouse Gas Abatement Cost Curve."; (2) International Energy Agency. 2008a. *World Energy Outlook 2008*. Paris: International Energy Agency.; and (3) International Energy Agency. 2008b. *Energy Technology Perspectives 2008: Scenarios and Strategies to 2050*. Paris: International Energy Agency.

We recommend that the estimated long-run marginal abatement cost be used as a practical and reasonable measure of the societal cost of carbon dioxide emissions. This can be applied to carbon dioxide emissions reductions, derived from lower electricity generation as a result of energy efficiency, in order to quantify their "full value." A portion of this value will be reflected in the allowance price for emissions, and thus internalized in the avoided costs; the balance may be referred to as an externality. Based on a review of these different sources, and our experience and judgment on the topic, we believe that it is reasonable to use an estimated long-term marginal abatement cost (LT MAC) of $80 per short t$CO_2$ equivalent (2011$) in evaluating the cost-effectiveness of energy efficiency measures. This estimate is essentially the same as our AESC 2009 estimate for the LT MAC of $81.52 per short t$CO_2$ equivalent (2011$).

Thus, states that have established targets for climate mitigation comparable to the targets discussed in this Chapter, or that are contemplating such action, could view the $80/ton long term abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of reductions in carbon emissions required to achieve those targets.

Estimates of long-run marginal abatement costs include a degree of uncertainty. These reflect the underlying assumptions about a variety of effects, among them the extent of technological innovation, the selected emission reduction targets, the technical potential of certain technologies, and international and national policy initiatives, along with a variety of other influencing factors. Of course, selection of this value requires multiple assumptions and cannot be definitive given the quickly evolving combination of scientific understanding of the causes, effects and scale of climate change, international policy initiatives, and technological advances. It will be necessary to continuously review available information, and determine what value is reasonable given information available at the time of reviews. A value of $80 per short ton of CO_2 reflects our experience that actual costs tend to be lower than modeled values,[189] and is a reasonable estimate of the long-run marginal abatement costs for achieving a stabilization target that is likely to avoid temperature increases higher than 2^{o}C above pre-industrial levels.

6.6.5. Estimating CO_2 Environmental Costs for New England

Our estimates of the "external" or additional cost associated with emissions of carbon dioxide in New England are based upon the sustainability target and the

[189] The long-run marginal abatement value of $80 per short ton CO_2 is slightly lower outside the range shown in Exhibit 6-6. The lowest value that would achieve atmospheric stabilization at 450 ppm as shown in the Exhibit is approximately $83.

forecast of carbon emission regulation in New England over the study period. The externality value for carbon dioxide in each year was calculated as the estimated long term marginal abatement cost of $80 per short ton minus the annual allowance values internalized in the projected electric energy market prices. For AESC 2011, we repeat this calculation process for the RGGI only scenario. These values are summarized in Exhibit 6-57.

Exhibit 6-57: CO_2 Externality Calculations

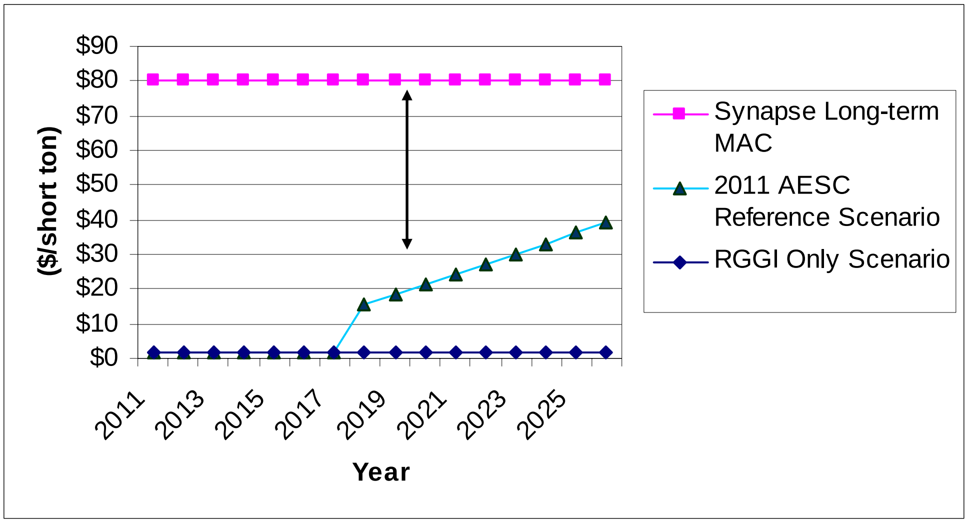
	LT MAC ($/short ton)	2011 AESC Reference Allowance Price ($/short ton)	2011 AESC Reference Externality ($/short ton)	RGGI Only Scenario Allowance Price ($/short ton)	RGGI Only Scenario Externality ($/short ton)
	a	b	c=a-b	d	e=a-d
2011	$80	$1.89	***$78.11***	$1.89	***$78.11***
2012	$80	$1.89	***$78.11***	$1.89	***$78.11***
2013	$80	$1.89	***$78.11***	$1.89	***$78.11***
2014	$80	$1.89	***$78.11***	$1.89	***$78.11***
2015	$80	$1.89	***$78.11***	$1.89	***$78.11***
2016	$80	$1.89	***$78.11***	$1.89	***$78.11***
2017	$80	$1.89	***$78.11***	$1.89	***$78.11***
2018	$80	$15.30	***$64.70***	$1.89	***$78.11***
2019	$80	$18.28	***$61.72***	$1.89	***$78.11***
2020	$80	$21.25	***$58.75***	$1.89	***$78.11***
2021	$80	$24.23	***$55.77***	$1.89	***$78.11***
2022	$80	$27.20	***$52.80***	$1.89	***$78.11***
2023	$80	$30.18	***$49.82***	$1.89	***$78.11***
2024	$80	$33.15	***$46.85***	$1.89	***$78.11***
2025	$80	$36.13	***$43.87***	$1.89	***$78.11***
2026	$80	$39.10	***$40.90***	$1.89	***$78.11***

Notes
Values expressed in 2011 Dollars
Allowance Prices from Exhibit 2-4
Inflation rate of 2%

The annual allowance values internalized in the projected electric energy market prices are shown in column b of Exhibit 6-57. The values are based upon a Synapse (Johnston 2011) forecast of the carbon trading price associated with anticipated carbon regulations starting in 2018. That carbon price was included in the dispatch model runs (in the generators' bids) and hence is embedded within the AESC 2011 avoided electricity costs. The additional value in each year is the difference between the estimate of long run marginal abatement cost ($80 per ton CO_2) and the value of the carbon trading price embedded in the projection of wholesale electric energy prices.

Exhibit 6-58 illustrates how the additional CO_2 cost was determined. The line for the allowance price is based on the forecast of carbon allowance costs, illustrating the notion that the United States will gradually move to incorporate the climate externality into policy. The "externality" is simply the difference between the estimate of the long-term marginal abatement cost (LT MAC) and the anticipated allowance cost; that is, the area above the line with triangles and below $80 per ton in the graph (shown between the double arrowed vertical line).

Exhibit 6-58: Determination of the Additional Cost of CO_2 Emissions



The carbon dioxide externality price forecast is presented above as a single simple price. This is for ease of application and because doing something more complex, such as varying the shape over time or developing a distribution to represent uncertainty, would go beyond the scope of this project and would stretch the available information upon which the externality price is based. We fully acknowledge the many complexities involved in estimating a carbon price, both conceptual and practical.

With regard to environmental costs, AESC 2011 focuses on the externality value of carbon dioxide for the purpose of screening DSM programs. There are, of course, many impacts of electric power production. A number of those impacts are listed above in Chapter 2. However, the bulk of displaced generation in New England will be from existing and future natural gas plants. For these, CO_2 emissions are the dominant non-internalized environmental cost.

6.6.6. Applying CO_2 Costs in Evaluations of DSM Programs

The externality values from Exhibit 6-57 above are incorporated in the avoided electricity cost workbooks and expressed as dollar per kWh based upon our analysis of the CO_2 emissions of the marginal generating units summarized in Exhibit 6-51.

At a minimum program administrators should calculate the costs and benefits of DSM programs with and without these values in order to assess their incremental impact on the cost-effectiveness of programs. However, we recommend the program administrators include these values in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation.

The Massachusetts Department of Public Utilities recently clarified its policies with regard to the avoided costs of energy efficiency programs. In light of the requirement of the Green Communities Act[190] to implement all cost-effective energy efficiency resources, the Department opened an investigation to update its energy efficiency guidelines, including policies regarding the types of costs and benefits that can be included in cost-effectiveness screening in Massachusetts.

The Department affirmed the use of the Total Resource Cost test, and clarified how environmental benefits could be used in evaluating cost-effectiveness. The Department cited a Supreme Judicial Court (SJC) case that addressed the circumstances under which the Department may require Program Administrators to account for environmental impacts in evaluating energy resources. The SJC found that the Department could not require Program Administrators to consider environmental externalities in evaluating energy resources, as it did not have the statutory authority to do so.[191]

However, the SJC made it clear that the Department does have the authority to require Program Administrators to include the costs of compliance with current and reasonably foreseeable future environmental regulations, as these compliance costs would be incorporated in electricity prices over which the Department has clear jurisdiction. The Department identified the Global Warming Solutions Act and federal measures to control greenhouse gas emissions as examples of existing and reasonably anticipated future environmental regulations, and made it clear that "the Department expects Program Administrators to include estimates of such compliance costs in the calculation of future avoided energy costs."[192]

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[190] *An Act Relative to Green Communities*, Acts of 2008, Chapter 169, July 2, 2008.

[191] *Investigation by the Department of Public Utilities on its Own Motion into Updating its Energy Efficiency Guidelines Consistent with an Act Relative to Green Communities*, Order, DPU 08-50-A, March 16, 2009, pages 14 and 15.

[192] *Investigation by the Department of Public Utilities on its Own Motion into Updating its Energy Efficiency Guidelines Consistent with an Act Relative to Green Communities*, Order, DPU 08-50-A, March 16, 2009, page 17.

The next section explains why a DSM program could result in CO_2 emission reductions even under a cap and trade regulatory framework.

6.6.7. Impact of DSM on Carbon Emissions Under a Cap and Trade Regulatory Framework (RGGI)

The Regional Greenhouse Gas Initiative is a cap and trade greenhouse gas program for power plants in the northeastern United States. Participant states include Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont, Maryland and New Jersey.[193] Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. Eleven rounds of auctions have currently occurred.

As currently designed, the program:

- Stabilize CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019;
- Allocate a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes. Allowances allocated for consumer benefit will be auctioned and the proceeds of the auction used for consumer benefit and strategic energy purposes; and
- Include certain offset provisions that increase flexibility to include opportunities outside the capped electricity generation sector.

With carbon dioxide emissions regulated under a cap and trade system, as assumed in this market price analysis, it is conceivable that a load reduction from a DSM program will not lead to a reduction in the amount of total system carbon dioxide emissions. The annual total system emissions for the affected facilities in the relevant region are, after all, capped. In the analysis that was documented in this report, the relevant cap and trade regulation is the Regional Greenhouse Gas Initiative (RGGI) for the period 2011 to 2017 and an assumed national cap and trade system thereafter. However, there are a number of reasons why a DSM program could result in CO_2 emission reductions, specifically:

- Reduction in load that reduces the cost (marginal or total cost) of achieving an emissions cap can result in a tightening of the cap. This is a complex interaction between the energy system and political and economic systems,

[193] New Jersey Governor Christie has announced that New Jersey will withdraw from RGGI at the end of 2011.

and is difficult or impossible to model, but the dynamic may reasonably be assumed to exist;

- Specific provisions in RGGI provide for a tightening or loosening of the cap (via adjustments to the offset provisions that are triggered at different price levels). It is unknown at this point whether and to what extent such "automatic" adjustments might be built into the US carbon regulatory system;
- It is also possible that DSM efforts will be accompanied by specific retirements or allocations of allowances that would cause them to have an impact on the overall system level of emissions (effectively tightening the cap); and
- To the extent that the cap and trade system "leaks" because of its geographic boundaries, one would expect the benefits of a carbon emissions reduction resulting from a DSM program to similarly "leak." That is, a load reduction in New York could cause reductions in generation (and emissions) at power plants in New York, Pennsylvania, and elsewhere. Because New York is in the RGGI cap and trade system, the emissions reductions realized at New York generating units may accrue as a result of increased sales of allowances from New York to other RGGI states. However, because Pennsylvania is not in the RGGI system, the emissions reductions at Pennsylvania generating units would be true reductions attributable to the DSM program.

The first three of these points, above, would also apply to a national CO_2 cap and trade program. The fourth point, about leakage and boundaries, would apply as well, but to a lesser extent.

6.7. Social Discount Rate

The Project Team surveyed Study Group members and other sources to summarize the real discount rate used in cost-effectiveness models for energy efficiency programs in the six New England States as well as California, New York, Oregon and Washington. Appendix C summarizes results from our survey of real discount rates.

Chapter 7: Sensitivity Analyses

Sensitivity analyses provide insights into the potential impacts of changes in key uncertain input assumptions. In addition they help increase the shelf life (or period of usability) of the report in the face of potential changes in market conditions over time. The latter benefit is particularly relevant to AESC 2011, which is typically revised every for two years. In the absence of sensitivity analysis results changes in market conditions between the time the report is distributed and the time avoided costs estimates are next updated might lead to questions about the robustness and usefulness of the analysis.

With this in mind, the Project Team working with the Study Group identified 1) natural gas prices and 2) carbon allowance prices as the key input assumptions for which sensitivity analyses should be prepared because of their uncertain nature and their large, direct impact on avoided electric-energy costs.

The major conclusions from the sensitivity analyses are:

- The annual average wholesale price of electric energy in New England would be approximately 14.3 percent higher ($71.58 versus $62.60 on a 15-year levelized basis) than our Reference Case forecast through 2026 under our natural gas High Price case, which has Henry Hub natural gas prices 17.6 percent higher than the Reference Case.
- The annual average wholesale price of electric energy in New England would be approximately 9.3 percent higher ($68.53 versus $62.60 on a 15 year levelized basis) than our Reference Case forecast through 2026 under our carbon High Price case, which has carbon compliance costs 90 percent higher on a 15-year levelized basis than the AESC 2011 Reference Case. This represents a change in the annual average wholesale price of electric energy of about $0.41/MWh for every $-per-ton change in the allowance price for CO_2 under the High Price Case relative to the Reference Case.

7.1. Sensitivity of Wholesale Electric Energy Prices to Changes in Natural Gas Prices at Henry Hub

As documented in previous chapters, natural-gas prices have a large, direct impact on avoided electric-energy costs.

For this sensitivity case we use our natural gas High Price case, under which wholesale natural gas prices are 17.6 percent higher at Henry Hub through 2026 on a 15 year levelized basis than those used in the Reference Case. The AESC natural gas High Price case is described in Chapter 3.

Henry Hub prices translate into a similar increase of 17.6 percent in the prices of natural gas delivered to electric generation units in New England, i.e. burner-tip prices.

The Henry Hub prices under the AESC natural gas Reference case and High Price case are shown in columns two and three of Exhibit 7-1. The last column in Exhibit 7-1 shows the impact on electricity prices using the high gas prices compared to the Reference Case Henry Hub natural gas.

Exhibit 7-1: Henry Hub Reference and Sensitivity Case Prices (2011$/million Btu)

Year	Reference NG Price	High NG Price	% Change in NG Price	% Change in Electricity Price
2012	$4.91	$4.91	-	-
2013	5.10	5.97	17.1%	14.7%
2014	5.29	6.22	17.6%	15.7%
2015	5.91	6.92	17.1%	15.7%
2016	5.96	7.07	18.6%	17.6%
2017	5.93	7.12	20.1%	18.3%
2018	5.95	7.24	21.7%	17.6%
2019	5.98	7.33	22.6%	17.6%
2020	6.06	7.23	19.3%	15.0%
2021	6.16	7.10	15.3%	11.9%
2022	6.25	7.28	16.5%	12.6%
2023	6.52	7.60	16.6%	12.7%
2024	6.72	7.95	18.3%	13.8%
2025	6.78	8.20	20.9%	15.1%
2026	6.89	8.40	21.9%	16.1%
Levelized	**$5.97**	**$7.02**	**17.6%**	**14.3%**

The gas prices in the High Price case do not represent variations in actual market prices of gas (e.g., weekly, monthly, or even annual). Instead, the High Price case provides a set of gas prices that reflect the range of upside uncertainty in gas prices in the long-term. Our expectation is that any revised forecasts of long-term avoided Henry Hub gas costs made prior to the anticipated AESC 2013 update would fall between the Reference Case and the High Case.

Exhibit 7-2 shows the impacts of the High Price Case gas prices on New England wholesale electric energy prices by costing period. The average 17.6 percent increase in the natural Henry Hub natural gas price results in an average 14.3 percent increase in annual wholesale electric energy prices. The level of increase varies by season and time period, but not dramatically.

Exhibit 7-2: Seasonal and Time Period Impacts of Henry Hub Price Changes

Season	Time of Day	High NG Price
Winter	Off-Peak	15.9%
	On-Peak	13.3%
	All-Hours	14.5%
Summer	Off-Peak	13.4%
	On-Peak	15.1%
	All-Hours	14.3%
Annual	All-Hours	14.3%

7.2. Sensitivity of Wholesale Electric-Energy Prices to Changes in Carbon-Dioxide-Allowance Prices

We tested the sensitivity of wholesale electric-energy prices to a range of possible changes in carbon-allowance prices in light of the uncertainty in long-run forecasts of those allowances. The low and high carbon forecast values are shown in Exhibit 7-3 below.

- The low carbon case provides a lower bound of CO_2 allowance prices for sensitivity analysis purposes. We draw the prices for this case from the "RGGI only" set of carbon dioxide allowance prices required under the scope of work.
- The high carbon price sensitivity case provides an upper bound estimate of CO_2 allowance prices for sensitivity analysis purposes. We draw the prices for this case from the February 2011 Synapse High Carbon price forecast. 194

[194] Johnston (2011).

For Massachusetts, the CO_2 allowance prices from the High Carbon Price case may be a reasonable proxy for the avoided cost of carbon reductions required to comply with the GWSA in the absence of new energy efficiency programs. The AESC 2011 Reference Case projects carbon emissions for the Massachusetts electric sector will be approximately 25 percent below 1990 levels by 2020. Those projected reductions comply with the GWSA general sector-wide average target for 2020, but the Massachusetts Clean Energy and Climate Plan for 2020 calls upon the electric sector to achieve a greater than average level of carbon reductions. Further, we expect it will become increasingly difficult to meet increasingly stringent GWSA targets after 2020. Thus, in order to meet the GWSA targets, the electric sector will likely need to reduce emissions beyond the reductions reflected in the AESC 2011 Reference Case.

Exhibit 7-3: Carbon Dioxide Reference and Sensitivity Case Prices

	CO_2 (2011$/short ton)		
Year	Reference	RGGI Forecast	High Forecast
2012	$1.89	$1.89	$1.89
2013	1.89	1.89	1.89
2014	1.89	1.89	1.89
2015	1.89	1.89	15.30
2016	1.89	1.89	19.72
2017	1.89	1.89	24.14
2018	15.30	1.89	28.56
2019	18.28	1.89	32.98
2020	21.25	1.89	37.40
2021	24.23	1.89	41.82
2022	27.20	1.89	46.24
2023	30.18	1.89	50.66
2024	33.15	1.89	55.08
2025	36.13	1.89	59.50
2026	39.10	1.89	63.92
Levelized (2012-2026)	$15.64	$1.89	$29.94

Exhibit 7-4 shows the annual CO_2 price differences relative to the Reference Case and their impacts on the average annual wholesale energy prices. The average effect on energy prices is about $0.45/MWh on average for each $1/ton change in CO_2 prices.[195]

Exhibit 7-4: Energy Price Impacts of CO_2 Price Changes (2011$)

	Low CO_2 Price		High CO_2 Price				
Year	**CO_2 Price Change ($/ton)**	**Energy Price Change ($/MWh)**	**CO_2 Price Change ($/ton)**	**Energy Price Change ($/MWh)**	**AESC 2011 Reference Case ($/MWh)**	**AESC 2011 High Carbon Sensitivity ($/MWh)**	**% Difference from Reference Case**
2012	$0.00		$0.00		$48.73	$49.03	0.6%
2013	0.00		0.00		$50.27	$50.57	0.6%
2014	0.00		0.00		$51.68	$52.12	0.9%
2015	0.00		13.41	$6.66	56.21	62.87	11.8%
2016	0.00		17.83	8.70	57.33	66.03	15.2%
2017	0.00		22.25	10.37	57.64	68.00	18.0%
2018	-13.41	-$6.22	13.26	5.73	64.47	70.20	8.9%
2019	-16.39	-7.64	14.70	5.85	65.29	71.14	9.0%
2020	-19.36	-9.20	16.15	6.45	65.37	71.82	9.9%
2021	-22.34	-10.68	17.59	6.75	67.19	73.95	10.1%
2022	-25.31	-12.23	19.04	7.32	69.00	76.32	10.6%
2023	-28.29	-13.68	20.48	7.56	72.46	80.02	10.4%
2024	-31.26	-15.17	21.93	8.27	74.44	82.71	11.1%
2025	-34.24	-16.84	23.37	8.50	75.61	84.12	11.2%
2026	-37.21	-17.85	24.82	9.31	77.68	86.98	12.0%
Average	**-$25.31**	**-$12.17**	**$18.74**	**$7.62**	**62.60**	**68.53**	**9.3%**
Ratio: $/MWh vs. $/ton		0.48		0.41			

195 The AESC 2011 results are quite close to the AESC 2009 calculated coefficient of $0.46/MWh on average for this effect, and the AESC 2011 result is consistent with the average marginal price being set by a natural gas plant with a heat rate slightly below 8,000 Btu/kWh.

Chapter 8: Usage Instructions

This Chapter provides instructions on how to apply the Reference Case avoided costs of electricity, how to estimate avoided costs of electricity for the High Gas Price sensitivity case and the High Carbon Price sensitivity case, and how to apply the Reference Case avoided costs of natural gas.

8.1. Reference Case Avoided Costs of Electricity

AESC 2011 provides detailed projections of avoided electricity costs for each New England state as well as for specific regions within Connecticut and Massachusetts. These projections are provided as two page tables in Appendix B. The EXCEL workbooks used to develop these tables are provided to Program Administrators.

Appendix B provides tables for the following reporting regions:

Exhibit 8-1: Appendix B Tables of Avoided Cost of Electricity

State	Table
Connecticut	Statewide
	Norwalk/Stamford
	Southwest Connecticut, excluding Norwalk/Stamford
	Southwest Connecticut, including Norwalk/Stamford
	Connecticut excluding all of Southwest Connecticut
Massachusetts	Statewide
	NEMA (Northeast Massachusetts)
	Massachusetts excluding NEMA
	SEMA (Southeast Massachusetts)
	WCMA (West-Central Massachusetts)
Maine	Statewide
New Hampshire	Statewide
Rhode Island	Statewide
Vermont	Statewide
Connecticut (nominal $)	Statewide
	Norwalk/Stamford
	Southwest Connecticut, excluding Norwalk/Stamford
	Southwest Connecticut, including Norwalk/Stamford
	Connecticut excluding all of Southwest Connecticut

The tables for each reporting region present avoided costs by year for the following ISO-NE defined costing periods:

- Summer On-Peak: The 16-hour block 6 am–10 pm, Monday–Friday (except ISO holidays), in the months of June–September (1,390 Hours, 15.9 percent of 8,760).[196]
- Summer Off-Peak: All other hours–10 pm–6 am, Monday–Friday, weekends, and ISO holidays in the months of June–September (1,530 Hours, 17.5 percent of 8,760).
- Winter On-Peak: The 16-hour block 6 am–10 pm, Monday–Friday (except ISO holidays), in the eight months of January–May and October–December (2,781 Hours, 31.7 percent of 8,760).
- Winter Off-peak: All other hours–10 pm-6 am, Monday–Friday, all day on weekends, and ISO holidays–in the months of January–May and October–December (3,059 Hours, 34.9 percent of 8,760)

The "all-hours" avoided electricity cost for a given year, or set of years, is equal to the hour-weighted average of avoided costs for each costing period of that year one.

All-hours avoided electricity cost = (15.9 percent *summer On-peak)+(17.5 percent *summer Off-peak)+ (31.7 * winter On-peak) + (34.9 percent * Winter Off-peak)

Page one of each reporting region table provides the following avoided cost components:

1. Avoided unit cost of electric energy;
2. Avoided unit cost of electric capacity by demand reduction bidding strategy;
3. Energy DRIPE and capacity DRIPE for 2012 installations;
4. Energy DRIPE and capacity DRIPE for 2013 installations; and
5. Avoided externality costs.

Page two of each reporting region table provides:

1. Wholesale avoided costs of electricity (energy and capacity)
2. Avoided REC costs to load
3. 2012 Energy DRIPE values
4. 2013 Energy DRIPE values

Each table provides illustrative levelized values for each category of avoided cost at the bottom of each cost column. These are computed using a real discount rate of 2.46 percent.

[196] ISO-NE holidays are New Year's Day, Memorial Day, July 4th, Labor Day, Thanksgiving Day, and Christmas.

8.2. Worksheet Structure and Terminology

For each reporting region / zone there is a two page table of avoided electricity costs.

8.2.1. Page One—Avoided Cost of Electricity Results

Reading from left to right the structure of page one of each table is as follows:

8.2.1.1. User Defined Inputs

The tables have the following default values for the following three input assumptions:

1. Wholesale Risk Premium – 9 percent[197],
2. Real Discount Rate – 2.46 percent
3. Percent of Capacity Bid into the FCM – 50 percent

Users may insert their own values for any or all of those three input assumptions.

8.2.1.2. Avoided Unit Cost of Electric Energy ($/kWh) (Columns a – d)

Avoided energy costs are presented by year for each of the four energy costing periods– Winter On-Peak, Winter Off-Peak, Summer-On Peak, and Summer Off-Peak.[198]

The generalized avoided energy cost in each period is calculated as: (modeled avoided wholesale energy cost + avoided renewable energy certificate cost) * (1 + wholesale risk premium).

8.2.1.3. Avoided Unit Cost of Electric Capacity, $/kW-yr (Columns e – g)

This section provides values for a PA to calculate the avoided capacity cost based on a simplified bidding strategy consisting of x percent of demand reductions from measures in each year bid into the FCA for that year and the remaining 1-x percent not bid in to any FCA. The default value for x is 50 percent. Users can insert their own input for that value in the user-defined inputs section of Table One. (See section 8.8.1 for a discussion of energy efficiency and the capacity market).

The components of the avoided capacity cost are as follows:

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[197] The wholesale risk premium for Vermont is 11.1% per Vermont DPS.

[198] The avoided energy costs are computed for the aggregate load shape in each zone by costing period, and are applicable to DSM programs reducing load roughly in proportion to existing load. Other resources, such as load management and distributed generation, may have very different load shapes and significantly different avoided energy costs. Baseload resources, such as combined-heat-and-power (CHP) systems, would tend to have lower avoided costs per kWh. Peaking resources, such as most non-CHP distributed generation and load management, would tend to have higher avoided costs per kWh.

- The Avoided Unit Cost of Capacity of a kW bid into the FCM in column e reflects an 8 percent adjustment to reflect losses from the customer meter to the ISO-NE delivery point.
- The Avoided Unit Cost of Capacity in column f for avoided capacity not bid into an FCA reflects upward adjustments for the wholesale risk premium, the reserve margin in that year, and also a 1.9 percent adjustment to reflect PTF losses. Because FCA auctions are set three years in advance of the actual delivery year, avoided capacity *not* bid into a FCA will not impact ISO-NE's determination of forecasted peak until 2016 for measures installed in 2012.
- The Weighted Average *Capacity Value* based on % bid in column g is the *weighted average* avoided capacity of column e and f reflecting an individual PA's percent of capacity that is bid into the Forward Capacity Market. The column presents a weighted average of 50 percent bid default value that may be changed by PA's to reflect specific bidding strategies.

Under this approach the avoided capacity cost in each year is equal to the Weighted Average *Capacity Value* in column g for the relevant year multiplied by the demand reduction in that year.

8.2.1.4. Demand-Reduction-Induced Price Effects (DRIPE) (Columns h – q)

Each table provides separate projections of energy DRIPE and capacity DRIPE for measures implemented in 2012 and in 2013 respectively.

The energy DRIPE values reported in each table reflect the relevant state regulations governing treatment of energy DRIPE. For Massachusetts and Connecticut zones, the energy DRIPE values are intrastate values only. For Maine, Vermont, Rhode Island and New Hampshire, the energy DRIPE values reflect both intrastate and rest of pool values.

The AESC 2011 capacity DRIPE values start in 2016 due to floor prices set through FCA 6 as described in Chapter 6.

8.2.1.5. Carbon Dioxide Avoided Externality Costs $/kWh (Columns r – u)

This section of the worksheet table provides estimates of CO_2 externality values developed for this Study (values for RI are from the RGGI only scenario). CO_2 externality values are presented by year for each of the four energy costing periods.

8.2.2. Page Two—Inputs to Avoided Cost Calculations

Reading from left to right the structure of page two is as follows:

8.2.2.1. Wholesale Avoided Costs of Electricity Energy. $ per kWh (Columns v – y)

The wholesale electric energy prices are from the Market Analytics simulation runs described in the description of the model results in Chapter 6. Values for RI are from the

RGGI only scenario described in the Chapter 7 Sensitivity Scenarios. Users should not normally need to use the input values directly, or to modify these values.

8.2.2.2. Capacity, $ per kW-year (Column z and aa)

The wholesale electric capacity prices and reserve margin requirements are from the relevant Chapter 6 sections. Users should not normally need to use the input values directly, or to modify these values.

8.2.2.3. Avoided REC Costs to Load $/kWh (Column ab)

The avoided REC costs are calculated based on REC prices and RPS requirements that are described in detail in Chapter 6. Users should not normally need to use the input values directly, or to modify these values.

8.2.2.4. Energy DRIPE Values $/kWh (Columns ac – ar)

The energy DRIPE values are calculated based energy DRIPE factors described in detail in Chapter 6. The Appendix B workbooks present both Intrastate and Rest of Pool energy DRIPE values for 2012 and 2013 installations. Users should not normally need to use the input values directly, or to modify these values.

8.3. Guide to Applying the Avoided Costs

Users have the ability to specify certain inputs as well as to choose which of the avoided cost components to include in their analyses.

8.3.1. User-Specified Inputs

The avoided cost results are based upon default values for three inputs that users can specify. They are 1) the wholesale risk premium of 9 percent (11.1% for Vermont) , 2) the real discount rate of 2.46 percent, and 3) a percentage of capacity bid into the Forward Capacity Market of 50 percent. The Excel workbook is designed to allow Program Administrators to specify their preferred values for those three inputs in the top left section of page one of each worksheet.

If a user wishes to specify a different value for any of the inputs, the user should enter the *new* value directly in the worksheet. The calculations in the worksheet are linked to these values and new avoided costs will be calculated automatically

Program administrators are responsible for developing and applying estimates of avoided transmission and distribution costs for their own specific system that would be **separate** inputs to the values in the provided tables. An application of avoided transmission and distribution costs is described below in Section 8.3.6.

8.3.2. Avoided Costs of Energy

Calculating the quantity reduction benefits of energy reductions in a given year requires an estimate of losses from the ISO delivery points to the end use in addition to an estimate of the reduction at the meter. Each PA should obtain, or calculate, the losses applicable to its specific system as discussed below in Section 8.6.

These avoided costs should be estimated as follows:

1. Reduction in winter peak energy at the end use
× winter peak energy losses from the ISO delivery points to the end use
× the *Winter Peak Energy* value for that year by costing period;

2. Reduction in winter off-peak energy at the end use
× winter off-peak energy losses from the ISO delivery points to the end use
× the *Winter Off-Peak Energy* value for that year by costing period;

3. Reduction in summer peak energy at the end use
× summer peak energy losses from the ISO delivery points to the end use
× the *Summer Peak Energy* value for that year by costing period;

4. Reduction in summer off-peak energy at the end use
× summer peak off-energy losses from the ISO delivery points to the end use
× the *Summer Off-Peak Energy* value for that year by costing period.

8.3.3. Capacity Costs Avoided by Reductions in Peak Demand

The quantity benefit of a reduction in peak demand in a given year will depend upon the approach the PA has taken and/or will take towards bidding the reduction in demand from the efficiency program in that year into the applicable FCAs. As discussed in the Capacity section of Chapter 6, a PA may achieve avoided capacity costs from reductions in peak demand through a range of approaches.

A PA will bid some percent of demand reduction into Forward Capacity Market, and withhold the remaining percent of demand reduction since there are issues of timing and funding that may not allow a PA to bid the full quantity of demand reduction with confidence. A PA would therefore obtain a combination of the value of the capacity that is bid into the FCM (highest value) as described in Section 8.3.3.1 and the market capacity value of a reduction in peak load (lowest value) as described in Section 8.3.3.2 based on the percent of capacity that is bid into the FCM.

Following are descriptions of how a PA can calculate the avoided cost of reductions in peak demand for the two extreme approaches and the simplified user-specified bid strategy.

8.3.3.1. Value of 100% Bid of demand reduction from first program year into the first relevant FCA (Column e)

A PA will obtain the highest benefit for the reductions in peak demand from an energy efficiency program by bidding the full anticipated reduction into the FCA for the first power year in which that program would produce reductions. Thus, a PA responsible for an efficiency program that is expected to start January 2012 would have had to have bid 100% of the anticipated reduction in demand from that program into FCA 3, which was held in 2009 for the power year starting June 1, 2012. There is some financial risk associated with bidding in advance, in particular the potential a regulator may not approve the anticipated program budget and/or the possibility the program may fail to produce the anticipated level of demand reductions.

The benefit of a reduction in peak demand from either an On-Peak or a Seasonal Peak resource in a given year starting 2012 is estimated as the result of:

> Average MW reduction at the meter for the relevant period in a given year
>
> × the Avoided Unit Cost of Capacity bid if a kW bid into the FCM for that year, which incorporates the market-clearing price in the forward capacity market and an ISO-NE loss factor of 8%.

If the benefits of demand reductions are to include capacity DRIPE, the benefits calculated above should be increased by the estimate of capacity DRIPE allowed under the regulatory framework applicable to that screening zone as follows:

> Average MW reduction at the meter bid into FCA for given year
> × capacity DRIPE for that year

8.3.3.2. Value of Zero Percent Bid of demand reduction into any FCA (column f)

For an efficiency program that produces reductions starting in 2012, there is no benefit of a reduction in peak demand until 2016, at which point the annual benefit is calculated as follows:

> MW reduction at the meter during system peak in a given year
>
> × summer peak-hour losses from the ISO delivery points to the end use
> × the Avoided Unit Cost of Capacity for that year, which is the FCA price for that year adjusted upward by the reserve margin that ISO-NE requires for that year, by the PTF losses, and the wholesale risk premium.

8.3.3.3. Value of 50 Percent Bid of demand reduction into FCM (Column g)

The column reflects a 50 percent weighted average of demand reduction into Forward Capacity Market. A PA would therefore obtain 50 percent of the value of the capacity that is bid into the FCM (highest value) as described in Section 8.3.3.1 and 50 percent of the market capacity value of a reduction in peak load (lowest value) as described in Section 8.3.3.2 based on the default percentage.

8.3.4. DRIPE

The provided workbook tables include energy and capacity DRIPE values based on installation year 2012 and 2013.

8.3.4.1. Capacity DRIPE

The price benefits of demand reductions are capacity DRIPE. A PA can estimate capacity DRIPE for 2012 and 2013 installations:

MW reduction at the meter during system peak in a given year

× summer peak-hour losses from the ISO delivery points to the end use
× capacity DRIPE for that year

8.3.4.2. Avoided Cost of Energy DRIPE

The price benefits of energy reductions are energy DRIPE. A PA can estimate energy DRIPE for 2012 and 2013 installations:

1. Reduction in annual winter on peak energy at the end use
× winter peak energy losses from ISO delivery to the end use
× the Winter On Peak Energy DRIPE;
2. Reduction in annual winter off-peak energy at the end use
× winter off-peak energy losses from ISO delivery to the end use
× the Winter Off-Peak Energy DRIPE;
3. Reduction in annual summer on peak energy at the end use
× summer peak energy losses from ISO delivery to the end use
× the Summer On Peak Energy DRIPE;
4. Reduction in annual summer off-peak energy at the end use
× summer off-peak energy losses from ISO delivery to the end use
× the Summer Off-Peak Energy DRIPE;

8.3.5. Avoided Cost of Carbon Externalities

The carbon externalities can be calculated as follows:

1. Reduction in winter peak energy at the end use
× winter peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Winter On Peak Energy* value for that year,
2. Reduction in winter off-peak energy at the end use
× winter off-peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Winter Off-Peak Energy* value for that year,
3. Reduction in summer peak energy at the end use
× summer peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Summer On Peak Energy* value for that year,

4. Reduction in summer off-peak energy at the end use
   × summer off-peak energy losses from the ISO delivery points to the end use
   × the *CO_2 Externality Summer Off-Peak Energy* value for that year

8.3.6. Local T&D Capacity Costs Avoided by Reductions in Peak Demand

Although not part of the provided tables, and should be based upon specific PA information, the benefits of peak demand reductions of avoided local transmission and distribution costs can be calculated as follows:

> Reduction in the peak demand used in estimating avoided transmission and distribution costs at the end use
>
> × the utility-specific estimate of avoided T&D costs in $/kW-year.[199]

8.4. Levelization Calculations

Illustrative levelized costs for each of the direct avoided costs are presented along the bottom of each table. These values are calculated for three periods (2012-2021, 2012-26, and 2012-41), using a 2.46 percent real discount rate assumed throughout this project.

For levelization calculations outside the three periods documented in the workbook, the following inputs are required:

- The real discount rate of 2.46 percent or other user specified discount rate
- The number or periods over the levelizing time frame. For instance, the period 2012-2021 contains 10 periods
- The avoided costs within the levelizing period

The Excel formula used to calculate levelized values in the workbook is:

$$\text{Present Value} = -PMT(Discount\_Rate, Period, (NPV(Discount\_Rate, Annual\_\text{cos}ts\_within\_period)$$

8.5. Converting Constant 2011 Dollars to Nominal Dollars

Unless specifically noted, all dollar values in AESC 2011 are presented in 2011 constant dollars. To convert constant dollars into nominal (current) dollars, a user would follow the formula:

$$\text{Nominal Value} = \frac{\text{Constant Value}_{2011\$}}{Conversion\,Factor\,to\ 2011\$}$$

[199] Most demand-response and load-management programs will not avoid transmission and distribution costs, since they are as likely to shift local loads to new hours as to reduce local peak load.

For instance, in order to convert an AESC 2011 $1 in 2012 into nominal 2012 dollars, one would use the AESC 2011 conversion factor from 2012 to 2011 of 0.98. Inserting the conversion factor into the equation above (Nominal $\text{Value}_{2012} = (\$1_{2011\$}/0.98)$) results in a value of $1.02 in nominal dollars.

The AESC 2011 conversion factors are presented in Appendix A, Exhibit A-3.

8.6. Comparisons to AESC 2009 Reference Case Avoided Costs of Electricity

A PA can prepare a comparison of the fifteen year levelized avoided costs of electricity from AESC 2011 for a given reporting location and costing period to the corresponding AESC 2009 results, such as the comparison presented in Exhibit 1-1, as follows:

- Identify the relevant reporting location and costing period
- For the relevant reporting location and costing period, obtain the yearly values of each component from AESC 2009 Appendix B. The potential components are avoided energy costs, avoided capacity costs (by type of bidding strategy), energy DRIPE, capacity DRIPE and carbon externality.
- Convert the AESC 2009 yearly values for each component from $2009 to $2011
- Calculate the 15 year levelized values of each AESC 2009 component
- For the relevant reporting location and costing period, obtain the fifteen year values of each component from AESC 2011 Appendix B.

8.7. Utility-Specific Costs to be Added/Considered by Program Administrators Not Included in Worksheets

This section details additional inputs that are not specifically included in the worksheet and not part of the AESC 2011 scope of work, but should be considered by program administrators.

8.7.1. Losses between the ISO Delivery Point and the End Use

The avoided energy and capacity costs, and the estimates of DRIPE, include energy and capacity losses on the ISO-administered pool transmission facilities (PTF), from the generator to the delivery points at which the PTF system connects to local non-PTF transmission or to distribution substations.

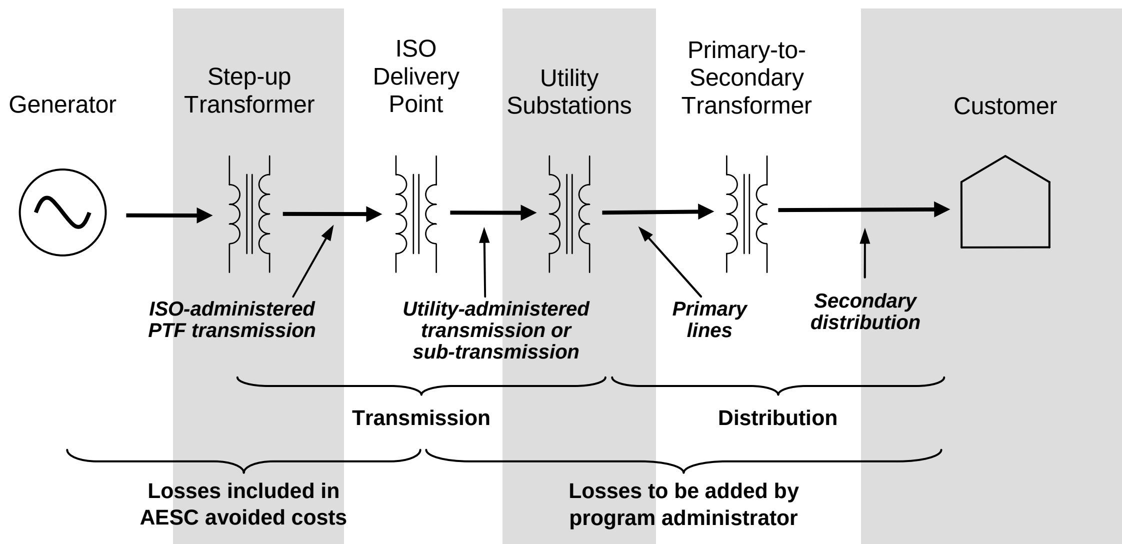
The presented values ***do not*** include the following losses:

- Losses over the non-PTF transmission substations and lines to distribution substations;
- Losses in distribution substations,

- Losses from the distribution substations to the line transformers on primary feeders and laterals,[200]
- Losses from the line transformers over the secondary lines and services to the customer meter,[201]
- Losses from the customer meter to the end use.

See Exhibit 8-2 that schematically illustrates the many types of losses on transmission and distribution systems highlighted in the list above.

Exhibit 8-2: Delivery-System Structure and Losses



In most cases, DSM program administrators measure demand savings from DSM programs at the end use. To be more comprehensive, the program administrator should estimate the losses from delivery points to the end uses. For example, if the energy delivered to the utility at the PTF is a, losses are b, and the customer received energy is c,

- Losses as a fraction of deliveries to the utility are $b \div a$,
- Losses as a fraction of deliveries to customers are $b \div c$.

[200] In some cases, this may involve multiple stages of transformers and distribution, as (for example) power is transformed from 115kV transmission to 34kV primary distribution and then to 14 kV primary distribution and then to 4 kV primary distribution, to which the line transformer is connected.

[201] Some customers receive their power from the utility at primary voltage. Since virtually all electricity is used at secondary voltages, these customers generally have line transformers on the customer side of the meter and secondary distribution within the customer facility.

Hence, each kilowatt or kilowatt-hour saved at the end use saves $1 + {}^{b}\!/\!{}_{c}$. The program administrator should estimate that ratio and multiply the end-use savings or benefits by that loss ratio. Loss ratios will be generally higher for higher-load periods than lower-load periods, since losses in wires (both within transformers and in lines) vary with the square of the load, for a given voltage and conductor type.

If the change in load does not change the capacity of the transmission and distribution system, then the losses should be computed as marginal losses, which are roughly twice the percentage as average line losses for the same load level.[202] Energy savings and/or growth do not generally result in changing the wire sizes. Hence, for energy avoided costs, losses are estimated on a marginal basis, so *a, b*, and *c* above are increments or derivatives, rather than total load values.

If the change in load results in a proportional change in transmission and distribution capacity, losses should be computed as the average losses for that load level. If the program administrator treats all load-carrying parts of the transmission and distribution as avoidable and varying with peak load, then only average losses should be applied to avoided capacity costs.

8.8. Energy Efficiency Programs and the Capacity Market

An energy efficiency program that produces a reduction in peak demand has the ability to avoid the wholesale capacity cost associated with that reduction. The capacity-cost amount that a particular reduction in peak demand will avoid in a given year will depend upon the approach that the program administrator responsible for that energy efficiency program takes towards bidding all, or some, of that reduction into the applicable FCAs.

A program administrator (PA) can choose an approach that ranges between bidding 100 percent of the anticipated demand reduction from the program into the relevant FCAs to bidding zero percent of the anticipated reduction into any FCA.

- A PA that wishes to bid 100 percent of the anticipated demand reduction from the program into the relevant FCA has to do so when that FCA is conducted, which can be up to three years in advance of the program implementation year. For example, a PA responsible for an efficiency program that will be implemented starting January 2012 would have had to have bid 100 percent of the forecast demand reduction for June 2012 onwards from that program into FCA 3, which was held in 2009. Since a bid is a firm financial commitment, there is an associated financial risk if the PA is unable to actually deliver the full demand

[202] In this sense, "line losses" does not include the no-load losses that result from eddy currents in the cores of transformers. These are often called "iron" losses (since transformer cores were historically made of iron), in contrast to the load-related "copper" losses of the lines and transformer windings.

reduction for whatever reason. The value of this approach is the compensation paid by ISO-NE, i.e. the quantity of peak reduction each year times the FCA price for the corresponding year.

- If a PA does not bid any of the anticipated demand reduction into any FCA, the program can still avoid some capacity costs if it has a measure life longer than three years.[203] Under this approach, a PA responsible for an efficiency program starting January 2012 simply implements that program. The customers' contribution to the ISO peak load, whenever that occurs in the summer of 2012, would be lower due to the program. This PA's customers would see some benefit from a lower capacity share starting in June 2013 (the following year). The reduced capacity requirement will reduce the capacity acquired in future FCAs, starting as early as the reconfiguration auctions for the power year starting in June 2013 and affecting all the auctions for the power years from June 2016 onward; the entire region will benefit from the reduction of capacity purchases.

Exhibit 8-3 below illustrates the various approaches that a Program Administrator could choose for avoiding wholesale capacity costs via a hypothetical energy efficiency measure that is implemented in 2012 and produces a 100 kW reduction for a five year period, 2012 to 2016. In this example, the PA considers three approaches.

The first approach is to bid 100 percent of the projected reduction, 100 kW, into each of the relevant FCAs. Under this approach the reduction avoids capacity costs roughly equals to its revenues from the FCM each year, i.e., l to 100 kW times the FCA price in each of the five years, 2012 through 2016.[204] However the PA would have had to bid that 100-kW reduction, scheduled to start in 2012, into each FCA from FCA 3 onward.

The second approach is to bid none of the projected reductions into any FCA. Under this approach the reduction avoids capacity costs equal to the value of the reduction in installed capacity it causes in 2016. That value is 100 kW increased by the reserve margin (15 percent for illustrative purposes) in 2016 and multiplied by the FCA price in 2016. The avoided capacity cost is limited to the impact in 2016 because ISO-NE sets the ICR) to be acquired in each power year three years in advance of that year. Thus, in this approach, ISO-NE would first see the 100 kW reduction as a lower actual peak load in

[203] In many cases, the PA is a utility; in other cases it is a state agency or other entity. In any case, the reduction in load benefits the customers served by the PA, whether they pay for generation supply through a utility standard-offer supply, an aggregator, or a competitive supplier.

[204] The price paid to a capacity resource in any year can vary from the price paid by load-serving entities by various factors, including PER deductions, availability penalties, multi-year prices for new resources, local reliability costs, etc.

2012. However, 2016 is the earliest power year for which ISO-NE could reflect the actual reduction in 2012 because, by July 2013 ISO-NE will have forecast peak load for 2016, set the ICR for 2016 and run the FCA for 2016.

The third illustrated approach is to bid 50 percent of the projected reduction, 50 kW, into each of the relevant FCAs.

Other approaches, not illustrated in Exhibit 8-3, would include bidding an increasing percentage of the 2012 load reduction into FCA3 and future auctions, as the PA becomes more confident in its estimates of the demonstrable savings.

Exhibit 8-3: Illustration of Alternative Approaches to Capturing Value from Reductions in Peak Demands

Hypothetical measure installed in 2010, reduces peak by 100 kw for 5 years								
ISO-NE sets NICR and Conducts FCA			Example 1—PA bids 100% of expected demand reduction into each corresponding FCA		Example 2—PA bids zero expected demand reduction into each corresponding FCA		Example 3—PA bids 50% of expected demand reduction into each corresponding FCA	
FCA #	**Calendar year**	FCA for power year Starting	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Reduction Bid into FCA	Impact of Reduction on NICR set for power year
			kw	kw	kw	kw	kw	kw
3	2009	6/1/2012	100		0		50	
4	2010	6/1/2013	100		0		50	
5	2011	6/1/2014	100		0		50	
6	2012	6/1/2015	100	0	0	0	50	0
7	2013	6/1/2016	100	0	0	0	50	0
8	2014	6/1/2017	0	0		0	0	0
9	2015	6/1/2018	0	0		0	0	0
10	2016	6/1/2019	0	0		**115**	0	**57.5**

8.9. Sensitivity Case Avoided Costs of Electricity

Chapter 7 provides avoided wholesale electric energy costs for a High Gas Price sensitivity case and for a High Carbon Price sensitivity case. Calculating the complete avoided cost of electricity under each of those sensitivity cases is not included in the AESC 2011 Scope of Work. However, a PA could use the results from those sensitivity cases to develop approximate estimates of the avoided costs of electricity for either, or both sensitivity cases.

The estimates developed through th**e** approach **described below** will be approximate because they **will** not reflect the changes in various components, relative to Reference Case values, that would occur with a change in wholesale electric energy costs. For example, an increase in wholesale electric energy costs under the High Gas Price would cause a decrease in the REC cost component.

8.9.1. High Gas Price Sensitivity Case

A PA could develop an approximate estimate of the fifteen year levelized avoided costs of electricity for the High Gas Price sensitivity case for a given reporting location by multiplying the wholesale avoided costs of electric energy for that location, on page two of the relevant Appendix B workbook, in each of the columns v, w, x and y, by 1.143 for each of the years 2012 through 2026. (The factor of 1.143 is the 14.3 percent increase reported in Exhibit 7-2 of Chapter 7 on an annual basis).[205]

8.9.2. High Carbon Price Sensitivity Case

A PA could develop an approximate estimate of the fifteen year levelized avoided costs of electricity for the High Carbon Price sensitivity case for a given reporting location by multiplying the wholesale avoided costs of electric energy for that location, on page two of the relevant Appendix B workbook, in each of the columns v, w, x and y, by 1.093 for each of the years 2012 through 2026. (The factor of 1.093 is the 9.3 percent average increase reported in Exhibit 7-4 of Chapter 7).[206]

8.10. Guide to Applying the Avoided Natural Gas Costs

The avoided cost for each end use by sector and the retail sector is the sum of the avoided cost of the gas sent out by the LDC and the avoidable distribution cost, called the avoidable LDC margin, applicable from the city gate to the burner tip for some LDCs. Other LDCs assume they will not avoid any distribution costs due to reductions in gas use from efficiency measures. For the LDCs with no avoided distribution cost, the avoided cost of gas by end-use is their avoided cost of gas delivered to their city-gate. Users will need to determine if the LDC has avoidable LDC margins or not.

Appendix D provides by end use of the value streams of avoided natural gas costs for both avoidable margins and no avoidable margins. These columns refer to 1) non-heating, 2) heating, and 3) all by sector.

Non-heating value streams apply to year round end-uses such as hot water where usage is generally constant over the year. As noted in Chapter 4, we find that non-heating uses represent 30 percent of usage in New England.

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[205] Exhibit 7-2 provides the impact by costing period. Using the costing period values provides a more precise approximation that accounts for seasonal differences.

[206] Exhibit 7-4 provides the annual impact of the high carbon prices through 2026.

Heating value streams apply to heating end-uses where usage is high during winter months. As noted in Chapter 4, we find that heating uses represent 70 percent of usage for New England.

All value streams are the weighted average of heating (70 percent) and non-heating (30 percent) avoided costs.

For each program and/or measure, users should choose the appropriate value stream to determine the avoided cost benefit stream in evaluating cost-effectiveness.

Appendix A: Common Financial Parameters for AESC 2011

AESC 2011 requires converting nominal dollars to constant 2011 dollars (2011$) as well as a using real discount rate for calculating illustrative levelized avoided costs, although the published workbooks in Appendix B allows users to specify their own discount rate.

AESC 2011 uses a long-term inflation rate and a real discount rate. Those values are summarized below:

Exhibit A-1: Summary of Common Financial Parameters AESC 2009 versus AESC 2011

	AESC 2009	**AESC 2011**
Inflation Rate	2.00%	2.00%
Real Discount Rate	2.22%	2.46%

Inflation Rate

AESC 2011 uses a forecast of long-term inflation rate of 2.00 percent. The 2.00 percent inflation is consistent with the twenty year annual average inflation rate from 1990 to 2010, of 2.16 percent, derived from the Gross Domestic Product (GDP) chain-type price index. In light of the current economic conditions, the Project Team also examined projections of long-term inflation made by the Congressional Budget Office (CBO) in January 2011. The CBO projections of long-term inflation are 2.0 percent.[1]

Real Discount Rate

AESC 2011 requires the calculation of illustrative levelized avoided costs expressed in 2011$ for intervals of 1) 10 years (2012-2021), 2) 15 years (2012-2026), and 3) 30 years (2012-2041) using an identified real discount rate.[2]

The derived the real discount rate for AESC 2011 is based upon February 2011 nominal rates of return for 30-year Treasury Bonds and the forecast long-term inflation rate (2.00 percent) according to this formula[3]:

Real discount rate = ((1+nominal long-term rate)/(1+inflation rate)-1)

This formula results a real discount rate of 2.46 percent that can be used for calculations of levelized costs through periods as long as thirty years. The AESC 2011 real discount rate is moderately higher than the rate of 2.22 percent used in AESC 2009. For comparison purposes we examined projections made by the CBO of nominal rates of

[1] CBO, *The Budget and Economic Outlook: Fiscal Years 2011 to 2021*, Summary page xi. Available at http://www.cbo.gov/doc.cfm?index=12039. Accessed on May 17, 2011.
[2] The Excel workbooks allow members of the Study Group to input any discount rate to calculate levelized avoided costs.
[3] This approach was used in AESC 2005, 2007, and 2009.

return for 10-year Treasury notes for the 2017-2021 period.[4] The CBO projections of nominal rates of return, which are in the order of 5.4 percent, result real discount rates of over 3.3 percent based on forecast inflation of 2.0 percent. However, because we are calculating levelized costs through periods as long as thirty years we are proposing to use a real discount rate of **2.46** percent. Exhi presents a summary of the values we compared.

Conversion to Constant 2011$

AESC 2011 requires all forecasts to be expressed in real 2011$. Therefore, the project team developed a set of inflators to convert nominal dollars from prior years (pre-2011) into 2011$ and a set of deflators to convert nominal dollars from future years (post-2011) into 2011$. The inflator and deflator values are presented in Exhibit.

The inflators are calculated from the Gross Domestic Product (GDP) chain-type price index published by the US Department of Commerce's Bureau of Economic Analysis (BEA).[5] Deflators for future values use the long-term inflation rate of 2.00 percent.

Escalation Assumptions for Various Avoided Cost Components

The Project Team developed escalation assumptions used to extrapolate the forecasts from 2027 through 2041. For example, for the period from 2027 to 2041 for the annual wholesale energy prices, AESC 2011 uses an escalation assumption based on the (2021-2026) compound annual growth rate of 2.94 percent based on the Market Analytics Results. For other value streams of avoided cost components, we note the escalation assumptions.

[4] Summary Table 2, CBO (2011).
[5] BEA, Table 1.1.9 Implicit Price Deflators for Gross Domestic Product, downloaded 2/15/2011.

Exhibit A-2: Comparison of Real Discount Rate Estimates

Comparative Estimates of Financial Parameters						
Parameter / Source	**AESC 2005**	**AESC 2007**	**AESC 2009**	**AESC 2011 Proposed 2/17/11**	**Congressional Budget Office (1, 2)**	
					Jan-2009	**Jan-2011**
Long Term Nominal Rate	4.32%	4.77%	3.78%	4.51%	5.40%	5.40%
Source	30 year T-Bills as of Spring 2005	30 year T-Bills as of March 2007	30 year T-Bills as of March 2009	30 year T-Bills as of February 2011	Forecast - 10 yr T notes 2013 - 2019	Forecast - 10 yr T notes 2017-2021
Inflation Rate (GDP Deflator)	2.25%	2.50%	2.00%	**2.00%**	1.90%	2.00%
Source	Consistent with long-term historic average inflation.	Consistent with 20 year historic average inflation.	Less than 20 year historic average inflation of 2.44%, but lowered in response to economic forecasts.	Consistent with 20 year historic average inflation of 2.16%, but slightly lower to reflect economic forecasts.	Consistent with GDP price index 2013 - 2019 forecast.	Consistent with GDP price index 2015 - 2021 forecast.
Long Term Real Rate (%)	2.02%	2.22%	2.22%	**2.46%**	3.43%	3.33%
Source	Derived from nominal rate for treasuries and inflation rate.					

CBO Sources:

1 *The Budget and Economic Outlook: Fiscal Years 2009 to 2019*, Congressional Budget Office, January 2009, Table B-1

2 *The Budget and Economic Outlook: Fiscal Years 2011 to 2021*, Congressional Budget Office, January 2011, Summary introduction and Table 2.

Exhibit A-3: GDP Price Index and Inflation Rate

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2011$
1990	72.20	0.00%	1.546
1991	74.76	3.54%	1.493
1992	76.53	2.37%	1.459
1993	78.22	2.21%	1.427
1994	79.87	2.11%	1.398
1995	81.54	2.08%	1.369
1996	83.09	1.90%	1.344
1997	84.56	1.77%	1.320
1998	85.51	1.13%	1.306
1999	86.77	1.47%	1.287
2000	88.65	2.17%	1.259
2001	90.65	2.26%	1.232
2002	92.12	1.62%	1.212
2003	94.10	2.15%	1.187
2004	96.77	2.84%	1.154
2005	100.00	3.34%	1.116
2006	103.26	3.26%	1.081
2007	106.30	2.94%	1.050
2008	108.62	2.19%	1.028
2009	109.62	0.92%	1.019
2010	110.65	0.95%	1.009
2011	**111.65**	**0.90%**[6]	**1.000**
2012	113.88	2.00%	0.980
2013	116.16	2.00%	0.961
2014	118.48	2.00%	0.942
2015	120.85	2.00%	0.924
2016	123.27	2.00%	0.906
2017	125.74	2.00%	0.888
2018	128.25	2.00%	0.871
2019	130.82	2.00%	0.853
2020	133.43	2.00%	0.837
2021	136.10	2.00%	0.820
2022	138.82	2.00%	0.804
2023	141.60	2.00%	0.788
2024	144.43	2.00%	0.773
2025	147.32	2.00%	0.758
2026	150.27	2.00%	0.743
2027	153.27	2.00%	0.728
2028	156.34	2.00%	0.714
2029	159.46	2.00%	0.700
2030	162.65	2.00%	0.686

[6] Ibid, page 41: "The GDP price index will rise 0.9 percent in 2011…"

Appendix B: Avoided Electricity Cost Results

Avoided Cost of Electricity (2011$) Results :　　CT　Connecticut (Statewide)　　Page One of Two

State CT

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.048	0.064	0.046														0.042	0.043	0.041	0.045
2012	0.059	0.050	0.070	0.050	37.50	0.00	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.060	0.052	0.073	0.051	36.76	0.00	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.062	0.054	0.075	0.053	36.76	0.00	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.068	0.059	0.080	0.058	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.069	0.059	0.087	0.059	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.070	0.061	0.087	0.058	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.075	0.067	0.097	0.065	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.075	0.068	0.094	0.065	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.078	0.068	0.091	0.067	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.079	0.070	0.091	0.068	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.082	0.072	0.094	0.071	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.087	0.076	0.099	0.075	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.090	0.078	0.101	0.077	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.091	0.079	0.102	0.079	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.092	0.080	0.105	0.079	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.095	0.082	0.108	0.081	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.098	0.084	0.111	0.083	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.101	0.086	0.114	0.086	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.104	0.089	0.117	0.088	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.107	0.091	0.120	0.091	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.110	0.093	0.124	0.094	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.114	0.096	0.127	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.099	0.131	0.099	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.121	0.101	0.135	0.102	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.125	0.104	0.138	0.106	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.129	0.107	0.142	0.109	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.133	0.110	0.146	0.112	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.137	0.113	0.151	0.116	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.141	0.116	0.155	0.119	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.146	0.120	0.159	0.123	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.069	0.060	0.084	0.059	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.075	0.065	0.089	0.064	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.092	0.079	0.106	0.078	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General　All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1　Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2　Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3　Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.057	0.041	43.20		0.0016																
2012	0.052	0.044	0.063	0.044	34.72	16.6%	0.0019	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.053	0.046	0.065	0.045	34.04	15.7%	0.0021	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.055	0.047	0.066	0.046	34.04	17.7%	0.0023	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.060	0.051	0.071	0.050	34.04	15.9%	0.0027	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.060	0.051	0.077	0.051	13.98	16.0%	0.0030	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.061	0.052	0.077	0.050	20.56	16.2%	0.0033	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.067	0.059	0.086	0.057	28.72	16.3%	0.0024	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.068	0.061	0.085	0.058	32.22	16.4%	0.0014	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.070	0.060	0.081	0.059	45.08	16.5%	0.0018	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.071	0.063	0.083	0.061	45.94	16.6%	0.0011	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.073	0.064	0.084	0.063	68.95	16.8%	0.0018	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.077	0.067	0.088	0.066	83.08	16.9%	0.0025	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.080	0.069	0.090	0.068	90.89	17.0%	0.0026	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.081	0.070	0.091	0.070	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.083	0.072	0.095	0.071	96.38	17.3%	0.0012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.086	0.074	0.098	0.073	97.20	17.4%	0.0011																
2028	0.089	0.076	0.101	0.075	97.68	17.5%	0.0010																
2029	0.091	0.078	0.104	0.078	97.80	17.7%	0.0009																
2030	0.094	0.080	0.107	0.080	97.92	17.8%	0.0008																
2031	0.097	0.083	0.110	0.083	98.04	17.9%	0.0008																
2032	0.100	0.085	0.113	0.085	98.04	18.1%	0.0008																
2033	0.104	0.087	0.116	0.088	98.04	18.2%	0.0008																
2034	0.107	0.090	0.119	0.090	98.04	18.3%	0.0008																
2035	0.110	0.092	0.123	0.093	98.04	18.5%	0.0008																
2036	0.114	0.095	0.126	0.096	98.04	18.6%	0.0008																
2037	0.117	0.097	0.130	0.099	98.04	18.7%	0.0008																
2038	0.121	0.100	0.133	0.102	98.04	18.9%	0.0008																
2039	0.125	0.103	0.137	0.105	98.04	19.0%	0.0008																
2040	0.129	0.106	0.141	0.108	98.04	19.1%	0.0008																
2041	0.133	0.109	0.145	0.112	98.04	19.3%	0.0008																
Levelized Cos																							
10 years (2012-2021)	0.061	0.053	0.075	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.066	0.058	0.079	0.056	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.083	0.071	0.095	0.070	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results : CT-NS Norwalk/Stamford

Page One of Two

State CT

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values: Energy				DRIPE: 2012 vintage measures Intrastate Values: Capacity (See note 2)	DRIPE: 2013 vintage measures Intrastate Values: Energy				DRIPE: 2013 vintage measures Intrastate Values: Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.050	0.071	0.050	37.50	0.00	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.061	0.053	0.074	0.052	36.76	0.00	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.063	0.055	0.076	0.053	36.76	0.00	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.069	0.059	0.081	0.058	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.070	0.060	0.088	0.059	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.070	0.061	0.088	0.059	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.076	0.068	0.098	0.065	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.076	0.068	0.095	0.066	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.079	0.069	0.091	0.067	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.080	0.070	0.092	0.068	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.083	0.073	0.095	0.071	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.088	0.077	0.100	0.076	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.091	0.079	0.102	0.078	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.092	0.079	0.103	0.079	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.106	0.080	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.096	0.083	0.109	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.099	0.085	0.112	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.102	0.087	0.115	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.105	0.089	0.118	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.108	0.092	0.122	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.111	0.094	0.125	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.115	0.097	0.129	0.098	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.119	0.100	0.132	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.122	0.102	0.136	0.104	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.126	0.105	0.140	0.107	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.130	0.108	0.144	0.110	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.134	0.111	0.148	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.138	0.114	0.152	0.117	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.143	0.117	0.156	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.147	0.121	0.161	0.124	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.060	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.066	0.090	0.065	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Page Two of Two

Zone: CT-NS

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.053	0.044	0.063	0.044	34.72	16.6%	0.0019	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.054	0.046	0.065	0.045	34.04	15.7%	0.0021	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.055	0.048	0.067	0.047	34.04	17.7%	0.0023	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.061	0.052	0.072	0.051	34.04	15.9%	0.0027	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.061	0.052	0.078	0.051	13.98	16.0%	0.0030	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.061	0.053	0.077	0.051	20.56	16.2%	0.0033	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.068	0.060	0.087	0.058	28.72	16.3%	0.0024	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.068	0.061	0.086	0.059	32.22	16.4%	0.0014	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.070	0.061	0.082	0.060	45.08	16.5%	0.0018	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.072	0.063	0.084	0.062	45.94	16.6%	0.0011	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.074	0.065	0.085	0.064	68.95	16.8%	0.0018	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.078	0.068	0.089	0.067	83.08	16.9%	0.0025	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.081	0.070	0.091	0.069	90.89	17.0%	0.0026	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.082	0.071	0.092	0.071	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.084	0.073	0.096	0.072	96.38	17.3%	0.0012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.087	0.075	0.099	0.074	97.20	17.4%	0.0011																
2028	0.090	0.077	0.102	0.076	97.68	17.5%	0.0010																
2029	0.092	0.079	0.105	0.079	97.80	17.7%	0.0009																
2030	0.095	0.081	0.108	0.081	97.92	17.8%	0.0008																
2031	0.098	0.083	0.111	0.083	98.04	17.9%	0.0008																
2032	0.101	0.086	0.114	0.086	98.04	18.1%	0.0008																
2033	0.105	0.088	0.117	0.089	98.04	18.2%	0.0008																
2034	0.108	0.091	0.121	0.091	98.04	18.3%	0.0008																
2035	0.111	0.093	0.124	0.094	98.04	18.5%	0.0008																
2036	0.115	0.096	0.128	0.097	98.04	18.6%	0.0008																
2037	0.119	0.099	0.131	0.100	98.04	18.7%	0.0008																
2038	0.122	0.101	0.135	0.103	98.04	18.9%	0.0008																
2039	0.126	0.104	0.139	0.106	98.04	19.0%	0.0008																
2040	0.130	0.107	0.143	0.110	98.04	19.1%	0.0008																
2041	0.134	0.110	0.147	0.113	98.04	19.3%	0.0008																
Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General — All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results : CT-R Page One of Two

State CT

Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.048	0.064	0.046														0.042	0.043	0.041	0.045
2012	0.059	0.050	0.070	0.049	37.50	0.00	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.060	0.052	0.072	0.051	36.76	0.00	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.062	0.053	0.074	0.052	36.76	0.00	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.068	0.058	0.080	0.057	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.068	0.059	0.087	0.058	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.069	0.060	0.086	0.058	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.075	0.066	0.096	0.064	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.075	0.067	0.093	0.065	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.077	0.067	0.090	0.066	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.078	0.069	0.090	0.067	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.081	0.072	0.093	0.070	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.086	0.075	0.098	0.074	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.089	0.077	0.100	0.076	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.090	0.078	0.101	0.078	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.091	0.079	0.104	0.078	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.094	0.081	0.107	0.080	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.097	0.083	0.110	0.082	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.100	0.085	0.113	0.085	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.103	0.088	0.116	0.087	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.106	0.090	0.119	0.090	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.109	0.092	0.122	0.093	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.113	0.095	0.126	0.096	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.116	0.098	0.130	0.098	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.120	0.100	0.133	0.101	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.124	0.103	0.137	0.105	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.127	0.106	0.141	0.108	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.131	0.109	0.145	0.111	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.136	0.112	0.149	0.114	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.140	0.115	0.153	0.118	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.144	0.118	0.158	0.121	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.069	0.060	0.083	0.058	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.074	0.064	0.088	0.063	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.091	0.078	0.105	0.078	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-R

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.050	0.042	0.057	0.040	43.20		0.0016																
2012	0.052	0.044	0.062	0.043	34.72	16.6%	0.0019	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.053	0.045	0.064	0.045	34.04	15.7%	0.0021	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.054	0.047	0.066	0.046	34.04	17.7%	0.0023	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0027	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0030	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0033	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.066	0.058	0.085	0.056	28.72	16.3%	0.0024	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.067	0.060	0.084	0.058	32.22	16.4%	0.0014	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.069	0.060	0.080	0.059	45.08	16.5%	0.0018	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.071	0.062	0.082	0.060	45.94	16.6%	0.0011	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.072	0.064	0.083	0.062	68.95	16.8%	0.0018	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.077	0.067	0.087	0.066	83.08	16.9%	0.0025	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.079	0.068	0.089	0.067	90.89	17.0%	0.0026	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.085	0.073	0.097	0.072	97.20	17.4%	0.0011																
2028	0.088	0.075	0.100	0.075	97.68	17.5%	0.0010																
2029	0.091	0.077	0.103	0.077	97.80	17.7%	0.0009																
2030	0.093	0.080	0.105	0.079	97.92	17.8%	0.0008																
2031	0.096	0.082	0.109	0.082	98.04	17.9%	0.0008																
2032	0.099	0.084	0.112	0.084	98.04	18.1%	0.0008																
2033	0.103	0.086	0.115	0.087	98.04	18.2%	0.0008																
2034	0.106	0.089	0.118	0.090	98.04	18.3%	0.0008																
2035	0.109	0.091	0.121	0.092	98.04	18.5%	0.0008																
2036	0.113	0.094	0.125	0.095	98.04	18.6%	0.0008																
2037	0.116	0.097	0.128	0.098	98.04	18.7%	0.0008																
2038	0.120	0.099	0.132	0.101	98.04	18.9%	0.0008																
2039	0.124	0.102	0.136	0.104	98.04	19.0%	0.0008																
2040	0.128	0.105	0.140	0.107	98.04	19.1%	0.0008																
2041	0.132	0.108	0.144	0.111	98.04	19.3%	0.0008																
Levelized Cos																							
10 years (2012-2021)	0.061	0.052	0.074	0.051	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.082	0.070	0.094	0.069	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

State CT

CT-SWe
Southwest Connecticut, excluding Norwalk/Stamford

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.050	0.071	0.050	37.50	*0.00*	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.061	0.053	0.073	0.052	36.76	*0.00*	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.063	0.054	0.076	0.053	36.76	*0.00*	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.069	0.059	0.081	0.058	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.070	0.060	0.088	0.059	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.070	0.061	0.088	0.059	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.076	0.067	0.098	0.065	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.076	0.068	0.095	0.066	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.079	0.068	0.091	0.067	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.080	0.070	0.092	0.068	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.083	0.073	0.095	0.071	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.088	0.077	0.100	0.076	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.091	0.079	0.102	0.078	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.092	0.079	0.103	0.079	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.106	0.079	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.096	0.083	0.109	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.099	0.085	0.112	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.102	0.087	0.115	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.105	0.089	0.118	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.108	0.092	0.121	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.111	0.094	0.125	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.115	0.097	0.128	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.118	0.100	0.132	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.122	0.102	0.136	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.126	0.105	0.140	0.107	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.130	0.108	0.144	0.110	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.134	0.111	0.148	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.138	0.114	0.152	0.117	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.143	0.117	0.156	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.147	0.121	0.161	0.124	105.88	129.87	117.88											0.022	0.023	0.022	0.023

Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.059	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.075	0.066	0.090	0.064	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Page Two of Two

Zone: CT-SWe

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.053	0.044	0.063	0.044	34.72	16.6%	0.0019	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.054	0.046	0.065	0.045	34.04	15.7%	0.0021	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.055	0.048	0.067	0.047	34.04	17.7%	0.0023	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.061	0.052	0.072	0.051	34.04	15.9%	0.0027	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.061	0.052	0.078	0.051	13.98	16.0%	0.0030	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.061	0.053	0.077	0.051	20.56	16.2%	0.0033	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.067	0.059	0.087	0.058	28.72	16.3%	0.0024	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.068	0.061	0.086	0.059	32.22	16.4%	0.0014	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.070	0.061	0.082	0.060	45.08	16.5%	0.0018	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.072	0.063	0.084	0.062	45.94	16.6%	0.0011	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.074	0.065	0.085	0.064	68.95	16.8%	0.0018	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.078	0.068	0.089	0.067	83.08	16.9%	0.0025	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.081	0.070	0.091	0.069	90.89	17.0%	0.0026	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.082	0.071	0.092	0.071	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.084	0.073	0.096	0.072	96.38	17.3%	0.0012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.087	0.075	0.099	0.074	97.20	17.4%	0.0011																
2028	0.089	0.077	0.102	0.076	97.68	17.5%	0.0010																
2029	0.092	0.079	0.105	0.078	97.80	17.7%	0.0009																
2030	0.095	0.081	0.108	0.081	97.92	17.8%	0.0008																
2031	0.098	0.083	0.111	0.083	98.04	17.9%	0.0008																
2032	0.101	0.086	0.114	0.086	98.04	18.1%	0.0008																
2033	0.105	0.088	0.117	0.089	98.04	18.2%	0.0008																
2034	0.108	0.091	0.120	0.091	98.04	18.3%	0.0008																
2035	0.111	0.093	0.124	0.094	98.04	18.5%	0.0008																
2036	0.115	0.096	0.127	0.097	98.04	18.6%	0.0008																
2037	0.118	0.098	0.131	0.100	98.04	18.7%	0.0008																
2038	0.122	0.101	0.135	0.103	98.04	18.9%	0.0008																
2039	0.126	0.104	0.139	0.106	98.04	19.0%	0.0008																
2040	0.130	0.107	0.143	0.110	98.04	19.1%	0.0008																
2041	0.134	0.110	0.147	0.113	98.04	19.3%	0.0008																
Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General — All Avoided Costs are in Year 2011 Dollars

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Avoided Cost of Electricity (2011$) Results :

CT-SWi
Southwest Connecticut, including Norwalk/Stamford

State CT

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.050	0.071	0.050	37.50	*0.00*	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.061	0.053	0.074	0.052	36.76	*0.00*	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.063	0.054	0.076	0.053	36.76	*0.00*	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.069	0.059	0.081	0.058	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.070	0.060	0.088	0.059	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.070	0.061	0.088	0.059	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.076	0.067	0.098	0.065	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.076	0.068	0.095	0.066	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.079	0.069	0.091	0.067	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.080	0.070	0.092	0.068	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.083	0.073	0.095	0.071	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.088	0.077	0.100	0.076	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.091	0.079	0.102	0.078	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.092	0.079	0.103	0.079	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.106	0.080	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.096	0.083	0.109	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.099	0.085	0.112	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.102	0.087	0.115	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.105	0.089	0.118	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.108	0.092	0.122	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.111	0.094	0.125	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.115	0.097	0.129	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.118	0.100	0.132	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.122	0.102	0.136	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.126	0.105	0.140	0.107	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.130	0.108	0.144	0.110	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.134	0.111	0.148	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.138	0.114	0.152	0.117	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.143	0.117	0.156	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.147	0.121	0.161	0.124	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.059	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.066	0.090	0.065	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General — All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-SWi

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.053	0.044	0.063	0.044	34.72	16.6%	0.0019	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.054	0.046	0.065	0.045	34.04	15.7%	0.0021	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.055	0.048	0.067	0.047	34.04	17.7%	0.0023	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.061	0.052	0.072	0.051	34.04	15.9%	0.0027	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.061	0.052	0.078	0.051	13.98	16.0%	0.0030	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.061	0.053	0.077	0.051	20.56	16.2%	0.0033	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.067	0.059	0.087	0.058	28.72	16.3%	0.0024	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.068	0.061	0.086	0.059	32.22	16.4%	0.0014	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.070	0.061	0.082	0.060	45.08	16.5%	0.0018	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.072	0.063	0.084	0.062	45.94	16.6%	0.0011	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.074	0.065	0.085	0.064	68.95	16.8%	0.0018	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.078	0.068	0.089	0.067	83.08	16.9%	0.0025	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.081	0.070	0.091	0.069	90.89	17.0%	0.0026	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.082	0.071	0.092	0.071	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.084	0.073	0.096	0.072	96.38	17.3%	0.0012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.087	0.075	0.099	0.074	97.20	17.4%	0.0011																
2028	0.090	0.077	0.102	0.076	97.68	17.5%	0.0010																
2029	0.092	0.079	0.105	0.079	97.80	17.7%	0.0009																
2030	0.095	0.081	0.108	0.081	97.92	17.8%	0.0008																
2031	0.098	0.083	0.111	0.083	98.04	17.9%	0.0008																
2032	0.101	0.086	0.114	0.086	98.04	18.1%	0.0008																
2033	0.105	0.088	0.117	0.089	98.04	18.2%	0.0008																
2034	0.108	0.091	0.120	0.091	98.04	18.3%	0.0008																
2035	0.111	0.093	0.124	0.094	98.04	18.5%	0.0008																
2036	0.115	0.096	0.127	0.097	98.04	18.6%	0.0008																
2037	0.118	0.098	0.131	0.100	98.04	18.7%	0.0008																
2038	0.122	0.101	0.135	0.103	98.04	18.9%	0.0008																
2039	0.126	0.104	0.139	0.106	98.04	19.0%	0.0008																
2040	0.130	0.107	0.143	0.110	98.04	19.1%	0.0008																
2041	0.134	0.110	0.147	0.113	98.04	19.3%	0.0008																
Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results : MA Massachusetts (Statewide)

Page One of Two

State MA

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values: Energy				DRIPE: 2012 vintage measures Intrastate Values: Capacity (See note 2)	DRIPE: 2013 vintage measures Intrastate Values: Energy				DRIPE: 2013 vintage measures Intrastate Values: Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.050	0.064	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.051	0.071	0.051	37.50	0.00	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.062	0.054	0.074	0.053	36.76	0.00	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.064	0.056	0.077	0.055	36.76	0.00	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.071	0.062	0.083	0.060	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.072	0.063	0.090	0.062	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.073	0.065	0.091	0.062	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.078	0.070	0.100	0.068	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.078	0.071	0.097	0.068	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.080	0.070	0.092	0.069	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.081	0.072	0.093	0.070	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.084	0.074	0.096	0.073	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.089	0.078	0.100	0.077	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.092	0.080	0.102	0.078	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.092	0.080	0.103	0.080	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.092	0.080	0.105	0.080	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.095	0.082	0.108	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.098	0.084	0.111	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.101	0.086	0.114	0.086	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.104	0.089	0.117	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.107	0.091	0.121	0.091	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.110	0.093	0.124	0.094	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.114	0.096	0.127	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.098	0.131	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.121	0.101	0.135	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.125	0.104	0.139	0.106	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.128	0.107	0.143	0.109	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.132	0.109	0.147	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.137	0.112	0.151	0.116	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.141	0.115	0.155	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.145	0.118	0.159	0.123	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.071	0.063	0.086	0.061	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.077	0.067	0.090	0.066	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.080	0.107	0.080	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: MA

	Wholesale Avoided Costs of Electricity							2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity		Avoided REC Costs to Load	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.050	0.042	0.056	0.040	43.20		0.0034																
2012	0.051	0.043	0.061	0.043	34.72	16.6%	0.0038	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.052	0.045	0.063	0.045	34.04	15.7%	0.0045	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.054	0.047	0.065	0.045	34.04	17.7%	0.0051	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0058	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0065	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0071	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.066	0.059	0.086	0.057	28.72	16.3%	0.0061	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.067	0.060	0.084	0.058	32.22	16.4%	0.0045	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.068	0.059	0.080	0.058	45.08	16.5%	0.0047	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.070	0.062	0.081	0.060	45.94	16.6%	0.0041	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.072	0.063	0.083	0.062	68.95	16.8%	0.0047	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.076	0.066	0.087	0.065	83.08	16.9%	0.0053	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.079	0.068	0.088	0.067	90.89	17.0%	0.0051	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0042	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.085	0.073	0.097	0.072	97.20	17.4%	0.0027																
2028	0.087	0.075	0.099	0.075	97.68	17.5%	0.0025																
2029	0.090	0.077	0.102	0.077	97.80	17.7%	0.0024																
2030	0.093	0.079	0.105	0.079	97.92	17.8%	0.0023																
2031	0.096	0.081	0.108	0.082	98.04	17.9%	0.0023																
2032	0.099	0.083	0.111	0.084	98.04	18.1%	0.0023																
2033	0.102	0.086	0.115	0.087	98.04	18.2%	0.0023																
2034	0.105	0.088	0.118	0.089	98.04	18.3%	0.0023																
2035	0.109	0.090	0.121	0.092	98.04	18.5%	0.0023																
2036	0.112	0.093	0.125	0.095	98.04	18.6%	0.0023																
2037	0.116	0.095	0.128	0.098	98.04	18.7%	0.0023																
2038	0.119	0.098	0.132	0.101	98.04	18.9%	0.0023																
2039	0.123	0.101	0.136	0.104	98.04	19.0%	0.0023																
2040	0.127	0.104	0.140	0.107	98.04	19.1%	0.0023																
2041	0.131	0.106	0.144	0.111	98.04	19.3%	0.0023																
Levelized Cos																							
10 years (2012-2021)	0.060	0.053	0.074	0.051	32.15		0.005	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.065	0.057	0.078	0.056	48.09		0.005	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.082	0.069	0.094	0.069	68.51		0.004	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results : MA-NEMA

NEMA (Northeast Massachusetts)

Page One of Two

State MA

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.064	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.051	0.070	0.051	37.50	*0.00*	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.062	0.054	0.073	0.053	36.76	*0.00*	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.064	0.056	0.076	0.055	36.76	*0.00*	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.070	0.061	0.082	0.060	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.072	0.062	0.090	0.061	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.072	0.064	0.090	0.061	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.078	0.070	0.099	0.067	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.077	0.070	0.096	0.067	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.079	0.069	0.091	0.068	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.080	0.071	0.092	0.069	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.083	0.073	0.094	0.072	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.088	0.077	0.099	0.075	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.090	0.079	0.101	0.077	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.091	0.079	0.101	0.079	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.091	0.079	0.104	0.078	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.094	0.081	0.107	0.080	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.097	0.083	0.110	0.082	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.099	0.085	0.113	0.085	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.102	0.087	0.116	0.087	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.105	0.089	0.119	0.090	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.109	0.092	0.122	0.092	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.112	0.094	0.126	0.095	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.115	0.097	0.129	0.098	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.119	0.099	0.133	0.101	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.123	0.102	0.137	0.104	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.126	0.104	0.140	0.107	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.130	0.107	0.144	0.110	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.134	0.110	0.149	0.114	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.139	0.113	0.153	0.117	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.143	0.116	0.157	0.121	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.071	0.062	0.085	0.061	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.067	0.090	0.065	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.092	0.079	0.106	0.079	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: MA-NEMA

	Wholesale Avoided Costs of Electricity						
	Energy				Capacity		Avoided REC Costs to Load
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.049	0.042	0.055	0.040	43.20		0.0034
2012	0.051	0.043	0.061	0.043	34.72	16.6%	0.0038
2013	0.052	0.045	0.062	0.044	34.04	15.7%	0.0045
2014	0.054	0.046	0.065	0.045	34.04	17.7%	0.0051
2015	0.059	0.050	0.070	0.049	34.04	15.9%	0.0058
2016	0.059	0.050	0.076	0.050	13.98	16.0%	0.0065
2017	0.059	0.052	0.075	0.049	20.56	16.2%	0.0071
2018	0.065	0.058	0.085	0.056	28.72	16.3%	0.0061
2019	0.066	0.060	0.084	0.057	32.22	16.4%	0.0045
2020	0.068	0.059	0.079	0.057	45.08	16.5%	0.0047
2021	0.069	0.061	0.080	0.059	45.94	16.6%	0.0041
2022	0.071	0.062	0.082	0.061	68.95	16.8%	0.0047
2023	0.075	0.065	0.085	0.064	83.08	16.9%	0.0053
2024	0.078	0.067	0.087	0.066	90.89	17.0%	0.0051
2025	0.079	0.068	0.089	0.068	94.32	17.1%	0.0042
2026	0.081	0.070	0.093	0.069	96.38	17.3%	0.0029
2027	0.083	0.071	0.095	0.071	97.20	17.4%	0.0027
2028	0.086	0.073	0.098	0.073	97.68	17.5%	0.0025
2029	0.089	0.075	0.101	0.075	97.80	17.7%	0.0024
2030	0.092	0.077	0.104	0.078	97.92	17.8%	0.0023
2031	0.094	0.080	0.107	0.080	98.04	17.9%	0.0023
2032	0.097	0.082	0.110	0.083	98.04	18.1%	0.0023
2033	0.100	0.084	0.113	0.085	98.04	18.2%	0.0023
2034	0.104	0.086	0.116	0.088	98.04	18.3%	0.0023
2035	0.107	0.089	0.120	0.090	98.04	18.5%	0.0023
2036	0.110	0.091	0.123	0.093	98.04	18.6%	0.0023
2037	0.114	0.093	0.127	0.096	98.04	18.7%	0.0023
2038	0.117	0.096	0.130	0.099	98.04	18.9%	0.0023
2039	0.121	0.099	0.134	0.102	98.04	19.0%	0.0023
2040	0.125	0.101	0.138	0.105	98.04	19.1%	0.0023
2041	0.129	0.104	0.142	0.108	98.04	19.3%	0.0023
Levelized Cos							
10 years (2012-2021)	0.060	0.052	0.073	0.051	32.15		0.005
15 years (2012-2026)	0.065	0.056	0.077	0.055	48.09		0.005
30 years (2012-2041)	0.081	0.068	0.093	0.068	68.51		0.004

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Levelized Cos																
10 years (2012-2021)	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

MA-R
Rest of Massachusetts (Massachusetts excluding NEMA)

Page One of Two

State MA

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.050	0.064	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.051	0.071	0.051	37.50	*0.00*	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.062	0.054	0.074	0.053	36.76	*0.00*	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.064	0.057	0.077	0.055	36.76	*0.00*	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.071	0.062	0.083	0.061	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.072	0.063	0.090	0.062	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.073	0.065	0.091	0.062	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.079	0.071	0.100	0.068	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.078	0.071	0.097	0.068	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.080	0.070	0.092	0.069	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.081	0.072	0.093	0.070	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.084	0.074	0.096	0.073	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.089	0.078	0.100	0.077	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.092	0.080	0.102	0.079	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.092	0.080	0.103	0.080	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.106	0.080	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.095	0.082	0.108	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.098	0.084	0.111	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.101	0.087	0.114	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.104	0.089	0.117	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.107	0.091	0.121	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.111	0.094	0.124	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.114	0.096	0.128	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.099	0.131	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.121	0.101	0.135	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.125	0.104	0.139	0.106	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.129	0.107	0.143	0.110	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.133	0.110	0.147	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.137	0.113	0.151	0.116	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.141	0.116	0.155	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.146	0.119	0.160	0.124	105.88	129.87	117.88											0.022	0.023	0.022	0.023

Levelized Costs																					
10 years (2012-2021)	0.071	0.063	0.086	0.062	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.077	0.068	0.091	0.066	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.080	0.107	0.080	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: MA-R

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.050	0.042	0.056	0.040	43.20		0.0034
2012	0.051	0.043	0.061	0.043	34.72	16.6%	0.0038
2013	0.052	0.045	0.063	0.045	34.04	15.7%	0.0045
2014	0.054	0.047	0.065	0.046	34.04	17.7%	0.0051
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0058
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0065
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0071
2018	0.066	0.059	0.086	0.057	28.72	16.3%	0.0061
2019	0.067	0.061	0.084	0.058	32.22	16.4%	0.0045
2020	0.068	0.060	0.080	0.058	45.08	16.5%	0.0047
2021	0.070	0.062	0.082	0.060	45.94	16.6%	0.0041
2022	0.072	0.063	0.083	0.062	68.95	16.8%	0.0047
2023	0.076	0.066	0.087	0.065	83.08	16.9%	0.0053
2024	0.079	0.068	0.088	0.067	90.89	17.0%	0.0051
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0042
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0029
2027	0.085	0.073	0.097	0.072	97.20	17.4%	0.0027
2028	0.087	0.075	0.100	0.075	97.68	17.5%	0.0025
2029	0.090	0.077	0.103	0.077	97.80	17.7%	0.0024
2030	0.093	0.079	0.105	0.079	97.92	17.8%	0.0023
2031	0.096	0.081	0.109	0.082	98.04	17.9%	0.0023
2032	0.099	0.084	0.112	0.084	98.04	18.1%	0.0023
2033	0.102	0.086	0.115	0.087	98.04	18.2%	0.0023
2034	0.106	0.088	0.118	0.090	98.04	18.3%	0.0023
2035	0.109	0.091	0.122	0.093	98.04	18.5%	0.0023
2036	0.112	0.093	0.125	0.095	98.04	18.6%	0.0023
2037	0.116	0.096	0.129	0.098	98.04	18.7%	0.0023
2038	0.120	0.098	0.133	0.101	98.04	18.9%	0.0023
2039	0.123	0.101	0.136	0.105	98.04	19.0%	0.0023
2040	0.127	0.104	0.140	0.108	98.04	19.1%	0.0023
2041	0.131	0.107	0.144	0.111	98.04	19.3%	0.0023
Levelized Cos							
10 years (2012-2021)	0.060	0.053	0.074	0.051	32.15		0.005
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.005
30 years (2012-2041)	0.082	0.070	0.094	0.070	68.51		0.004

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Levelized Cos																
10 years (2012-2021)	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

MA-SEMA
SEMA (Southeast Massachusetts)

Page One of Two

State MA

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.050	0.063	0.047														0.042	0.043	0.041	0.045
2012	0.059	0.051	0.070	0.051	37.50	0.00	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.061	0.054	0.072	0.053	36.76	0.00	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.063	0.056	0.075	0.055	36.76	0.00	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.070	0.062	0.081	0.060	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.071	0.063	0.089	0.061	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.072	0.065	0.089	0.062	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.077	0.070	0.098	0.068	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.077	0.071	0.095	0.067	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.079	0.070	0.091	0.069	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.080	0.072	0.092	0.070	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.083	0.074	0.095	0.072	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.088	0.078	0.099	0.077	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.091	0.080	0.101	0.078	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.092	0.080	0.102	0.080	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.092	0.080	0.105	0.080	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.095	0.082	0.108	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.097	0.084	0.111	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.100	0.086	0.114	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.103	0.089	0.117	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.106	0.091	0.120	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.110	0.094	0.124	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.113	0.096	0.128	0.098	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.099	0.131	0.101	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.120	0.101	0.135	0.104	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.124	0.104	0.139	0.107	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.128	0.107	0.143	0.111	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.132	0.110	0.147	0.114	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.136	0.113	0.152	0.118	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.140	0.116	0.156	0.121	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.145	0.119	0.161	0.125	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.071	0.063	0.085	0.061	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.067	0.089	0.066	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.080	0.106	0.080	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General: All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: MA-SEMA

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.049	0.042	0.055	0.040	43.20		0.0034																
2012	0.051	0.043	0.060	0.043	34.72	16.6%	0.0038	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.052	0.045	0.062	0.044	34.04	15.7%	0.0045	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.053	0.047	0.064	0.045	34.04	17.7%	0.0051	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.058	0.051	0.069	0.049	34.04	15.9%	0.0058	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.059	0.051	0.075	0.050	13.98	16.0%	0.0065	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.059	0.052	0.075	0.049	20.56	16.2%	0.0071	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.065	0.058	0.084	0.056	28.72	16.3%	0.0061	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.066	0.060	0.083	0.057	32.22	16.4%	0.0045	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.068	0.059	0.079	0.058	45.08	16.5%	0.0047	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.070	0.062	0.081	0.060	45.94	16.6%	0.0041	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.071	0.063	0.082	0.062	68.95	16.8%	0.0047	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.076	0.066	0.086	0.065	83.08	16.9%	0.0053	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.078	0.068	0.087	0.067	90.89	17.0%	0.0051	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.080	0.069	0.089	0.069	94.32	17.1%	0.0042	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.082	0.071	0.093	0.070	96.38	17.3%	0.0029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.084	0.073	0.096	0.073	97.20	17.4%	0.0027																
2028	0.087	0.075	0.099	0.075	97.68	17.5%	0.0025																
2029	0.090	0.077	0.102	0.077	97.80	17.7%	0.0024																
2030	0.092	0.079	0.105	0.080	97.92	17.8%	0.0023																
2031	0.095	0.081	0.108	0.082	98.04	17.9%	0.0023																
2032	0.098	0.084	0.111	0.085	98.04	18.1%	0.0023																
2033	0.102	0.086	0.115	0.088	98.04	18.2%	0.0023																
2034	0.105	0.088	0.118	0.090	98.04	18.3%	0.0023																
2035	0.108	0.091	0.122	0.093	98.04	18.5%	0.0023																
2036	0.112	0.093	0.125	0.096	98.04	18.6%	0.0023																
2037	0.115	0.096	0.129	0.099	98.04	18.7%	0.0023																
2038	0.119	0.098	0.133	0.102	98.04	18.9%	0.0023																
2039	0.123	0.101	0.137	0.106	98.04	19.0%	0.0023																
2040	0.127	0.104	0.141	0.109	98.04	19.1%	0.0023																
2041	0.131	0.107	0.145	0.113	98.04	19.3%	0.0023																

Levelized Cos																							
10 years (2012-2021)	0.060	0.052	0.073	0.051	32.15		0.005	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.065	0.057	0.077	0.055	48.09		0.005	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.081	0.069	0.094	0.070	68.51		0.004	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

MA-WCMA
WCMA (West-Central Massachusetts)

Page One of Two

State MA

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.050	0.065	0.048														0.042	0.043	0.041	0.045
2012	0.060	0.052	0.071	0.052	37.50	0.00	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.062	0.055	0.074	0.054	36.76	0.00	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.065	0.057	0.077	0.055	36.76	0.00	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.071	0.062	0.083	0.061	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.072	0.062	0.090	0.062	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.073	0.064	0.090	0.062	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.079	0.070	0.100	0.068	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.078	0.070	0.096	0.068	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.080	0.070	0.093	0.069	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.081	0.072	0.094	0.070	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.084	0.075	0.096	0.073	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.089	0.078	0.101	0.077	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.092	0.080	0.102	0.079	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.092	0.080	0.103	0.080	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.105	0.080	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.095	0.083	0.108	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.098	0.085	0.111	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.101	0.087	0.114	0.086	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.104	0.089	0.117	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.107	0.092	0.120	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.110	0.094	0.123	0.094	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.114	0.097	0.126	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.099	0.130	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.121	0.102	0.133	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.124	0.105	0.137	0.106	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.128	0.108	0.141	0.109	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.132	0.110	0.144	0.112	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.136	0.113	0.148	0.116	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.140	0.117	0.152	0.119	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.145	0.120	0.157	0.123	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.072	0.063	0.086	0.062	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.077	0.068	0.091	0.066	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.080	0.106	0.080	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: MA-WCMA

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.050	0.042	0.056	0.040	43.20		0.0034																
2012	0.052	0.044	0.062	0.044	34.72	16.6%	0.0038	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.053	0.046	0.063	0.045	34.04	15.7%	0.0045	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.054	0.047	0.066	0.046	34.04	17.7%	0.0051	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0058	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0065	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0071	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.066	0.058	0.085	0.057	28.72	16.3%	0.0061	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.067	0.060	0.084	0.058	32.22	16.4%	0.0045	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.069	0.060	0.080	0.059	45.08	16.5%	0.0047	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.071	0.062	0.082	0.060	45.94	16.6%	0.0041	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.072	0.064	0.083	0.062	68.95	16.8%	0.0047	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.077	0.067	0.087	0.066	83.08	16.9%	0.0053	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.079	0.068	0.089	0.067	90.89	17.0%	0.0051	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0042	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.085	0.073	0.096	0.072	97.20	17.4%	0.0027																
2028	0.087	0.075	0.099	0.075	97.68	17.5%	0.0025																
2029	0.090	0.077	0.102	0.077	97.80	17.7%	0.0024																
2030	0.093	0.080	0.105	0.079	97.92	17.8%	0.0023																
2031	0.096	0.082	0.108	0.082	98.04	17.9%	0.0023																
2032	0.099	0.084	0.111	0.084	98.04	18.1%	0.0023																
2033	0.102	0.086	0.114	0.087	98.04	18.2%	0.0023																
2034	0.105	0.089	0.117	0.089	98.04	18.3%	0.0023																
2035	0.108	0.091	0.120	0.092	98.04	18.5%	0.0023																
2036	0.112	0.094	0.123	0.095	98.04	18.6%	0.0023																
2037	0.115	0.096	0.127	0.098	98.04	18.7%	0.0023																
2038	0.119	0.099	0.130	0.101	98.04	18.9%	0.0023																
2039	0.123	0.102	0.134	0.104	98.04	19.0%	0.0023																
2040	0.127	0.105	0.138	0.107	98.04	19.1%	0.0023																
2041	0.130	0.108	0.141	0.110	98.04	19.3%	0.0023																
Levelized Cos																							
10 years (2012-2021)	0.061	0.053	0.074	0.051	32.15		0.005	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.005	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.082	0.070	0.094	0.069	68.51		0.004	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

ME
Maine

State ME

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values: Energy				DRIPE: 2012 vintage measures Intrastate Values: Capacity (See note 2)	DRIPE: 2013 vintage measures Intrastate Values: Energy				DRIPE: 2013 vintage measures Intrastate Values: Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.052	0.046	0.054	0.042														0.042	0.043	0.041	0.045
2012	0.054	0.047	0.059	0.046	37.50	*0.00*	18.75	0.007	0.006	0.008	0.007	$0.00						0.042	0.043	0.041	0.045
2013	0.055	0.049	0.058	0.047	36.76	*0.00*	18.38	0.007	0.006	0.008	0.007	$0.00	0.007	0.006	0.008	0.007	$0.00	0.042	0.043	0.041	0.045
2014	0.055	0.049	0.059	0.047	36.76	*0.00*	18.38	0.007	0.006	0.008	0.007	$0.00	0.007	0.006	0.008	0.007	$0.00	0.042	0.043	0.041	0.045
2015	0.060	0.053	0.064	0.052	36.76	0.00	18.38	0.008	0.006	0.008	0.007	$0.00	0.008	0.006	0.008	0.008	$0.00	0.042	0.043	0.041	0.045
2016	0.061	0.053	0.066	0.052	15.09	18.01	16.55	0.007	0.006	0.008	0.007	$15.79	0.008	0.006	0.009	0.008	$15.79	0.042	0.043	0.041	0.045
2017	0.061	0.054	0.065	0.052	22.21	26.54	24.37	0.007	0.006	0.008	0.007	$15.85	0.007	0.006	0.008	0.007	$15.85	0.042	0.043	0.041	0.045
2018	0.067	0.060	0.072	0.058	31.01	37.09	34.05	0.008	0.007	0.009	0.008	$15.95	0.008	0.007	0.009	0.008	$15.95	0.035	0.036	0.034	0.037
2019	0.068	0.062	0.073	0.059	34.80	41.66	38.23	0.008	0.007	0.009	0.008	$15.32	0.008	0.007	0.009	0.008	$15.32	0.034	0.034	0.033	0.035
2020	0.070	0.061	0.075	0.060	48.69	58.34	53.52	0.004	0.003	0.004	0.004	$5.11	0.004	0.007	0.008	0.008	$5.11	0.032	0.033	0.031	0.034
2021	0.071	0.064	0.077	0.062	49.61	59.51	54.56	0.004	0.003	0.004	0.004	$5.14	0.004	0.003	0.004	0.004	$5.14	0.030	0.031	0.030	0.032
2022	0.074	0.065	0.079	0.065	74.46	89.42	81.94	0.003	0.003	0.003	0.003	$51.76	0.003	0.003	0.004	0.004	$51.76	0.029	0.029	0.028	0.030
2023	0.079	0.069	0.084	0.068	89.72	107.86	98.79	0.003	0.002	0.003	0.003	$25.52	0.003	0.003	0.004	0.003	$25.52	0.027	0.028	0.026	0.029
2024	0.082	0.071	0.086	0.071	98.16	118.14	108.15	0.003	0.002	0.003	0.003	$12.20	0.003	0.003	0.003	0.003	$12.20	0.025	0.026	0.025	0.027
2025	0.082	0.072	0.087	0.072	101.86	122.72	112.29					$6.21					$6.21	0.024	0.024	0.023	0.025
2026	0.083	0.072	0.087	0.071	104.09	125.53	114.81					$2.68					$2.68	0.022	0.023	0.022	0.023
2027	0.087	0.075	0.089	0.074	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.089	0.077	0.091	0.076	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.092	0.078	0.094	0.078	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.095	0.080	0.096	0.080	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.098	0.082	0.098	0.083	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.101	0.084	0.100	0.085	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.104	0.087	0.103	0.088	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.107	0.089	0.105	0.090	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.111	0.091	0.107	0.093	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.114	0.093	0.110	0.095	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.118	0.096	0.112	0.098	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.122	0.098	0.115	0.101	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.125	0.101	0.118	0.104	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.129	0.103	0.121	0.107	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.133	0.106	0.123	0.110	105.88	129.87	117.88											0.022	0.023	0.022	0.023

Levelized Costs	a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u
10 years (2012-2021)	0.062	0.055	0.066	0.053	34.73	22.58	28.65	0.007	0.006	0.007	0.007	7.06	0.006	0.006	0.007	0.006	7.23	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.067	0.059	0.072	0.058	51.93	48.94	50.44	0.005	0.004	0.006	0.005	10.93	0.005	0.004	0.006	0.005	11.20	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.083	0.071	0.085	0.071	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: ME

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.047	0.042	0.049	0.038	43.20		0.0004																
2012	0.049	0.043	0.053	0.041	34.72	16.6%	0.0007	0.007	0.006	0.008	0.007	0.033	0.024	0.046	0.026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.050	0.044	0.052	0.042	34.04	15.7%	0.0008	0.007	0.006	0.008	0.007	0.034	0.025	0.047	0.027	0.007	0.006	0.008	0.007	0.035	0.026	0.048	0.028
2014	0.050	0.044	0.053	0.043	34.04	17.7%	0.0010	0.007	0.006	0.008	0.007	0.035	0.025	0.049	0.027	0.007	0.006	0.008	0.007	0.035	0.026	0.050	0.028
2015	0.054	0.048	0.057	0.046	34.04	15.9%	0.0012	0.008	0.006	0.008	0.007	0.038	0.028	0.052	0.030	0.008	0.006	0.008	0.008	0.039	0.028	0.054	0.031
2016	0.054	0.047	0.060	0.047	13.98	16.0%	0.0013	0.007	0.006	0.008	0.007	0.036	0.026	0.054	0.029	0.008	0.006	0.009	0.008	0.039	0.028	0.058	0.031
2017	0.055	0.048	0.059	0.046	20.56	16.2%	0.0015	0.007	0.006	0.008	0.007	0.036	0.027	0.053	0.028	0.007	0.006	0.008	0.007	0.037	0.028	0.055	0.029
2018	0.060	0.054	0.065	0.052	28.72	16.3%	0.0010	0.008	0.007	0.009	0.008	0.040	0.030	0.060	0.032	0.008	0.007	0.009	0.008	0.040	0.031	0.061	0.033
2019	0.061	0.056	0.066	0.054	32.22	16.4%	0.0006	0.008	0.007	0.009	0.008	0.040	0.030	0.058	0.032	0.008	0.007	0.009	0.008	0.040	0.031	0.059	0.033
2020	0.063	0.055	0.068	0.055	45.08	16.5%	0.0008	0.004	0.003	0.004	0.004	0.020	0.015	0.027	0.016	0.004	0.007	0.008	0.008	0.021	0.031	0.056	0.033
2021	0.065	0.058	0.070	0.056	45.94	16.6%	0.0004	0.004	0.003	0.004	0.004	0.019	0.014	0.025	0.015	0.004	0.003	0.004	0.004	0.019	0.016	0.028	0.017
2022	0.067	0.059	0.072	0.059	68.95	16.8%	0.0008	0.003	0.003	0.003	0.003	0.017	0.013	0.022	0.014	0.003	0.003	0.004	0.004	0.017	0.014	0.026	0.016
2023	0.071	0.062	0.076	0.061	83.08	16.9%	0.0011	0.003	0.002	0.003	0.003	0.015	0.011	0.020	0.012	0.003	0.003	0.004	0.003	0.016	0.013	0.024	0.014
2024	0.074	0.064	0.078	0.064	90.89	17.0%	0.0012	0.003	0.002	0.003	0.003	0.014	0.010	0.018	0.011	0.003	0.003	0.003	0.003	0.014	0.012	0.021	0.013
2025	0.075	0.065	0.079	0.065	94.32	17.1%	0.0009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.003	0.003	0.000	0.010	0.018	0.011
2026	0.076	0.066	0.079	0.065	96.38	17.3%	0.0005	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.078	0.068	0.081	0.067	97.20	17.4%	0.0010																
2028	0.081	0.069	0.083	0.069	97.68	17.5%	0.0010																
2029	0.083	0.071	0.085	0.071	97.80	17.7%	0.0010																
2030	0.086	0.073	0.087	0.073	97.92	17.8%	0.0009																
2031	0.089	0.075	0.089	0.075	98.04	17.9%	0.0009																
2032	0.092	0.077	0.091	0.077	98.04	18.1%	0.0009																
2033	0.095	0.079	0.093	0.079	98.04	18.2%	0.0009																
2034	0.098	0.081	0.095	0.082	98.04	18.3%	0.0009																
2035	0.101	0.083	0.098	0.084	98.04	18.5%	0.0009																
2036	0.104	0.085	0.100	0.087	98.04	18.6%	0.0009																
2037	0.107	0.087	0.102	0.089	98.04	18.7%	0.0009																
2038	0.111	0.089	0.105	0.092	98.04	18.9%	0.0009																
2039	0.114	0.091	0.107	0.094	98.04	19.0%	0.0009																
2040	0.118	0.094	0.110	0.097	98.04	19.1%	0.0009																
2041	0.122	0.096	0.112	0.100	98.04	19.3%	0.0009																
Levelized Cos																							
10 years (2012-2021)	0.056	0.049	0.060	0.048	32.15		0.001	0.007	0.006	0.007	0.007	0.033	0.025	0.047	0.026	0.006	0.005	0.007	0.006	0.030	0.024	0.046	0.026
15 years (2012-2026)	0.061	0.053	0.065	0.052	48.09		0.001	0.005	0.004	0.006	0.005	0.026	0.019	0.037	0.021	0.005	0.004	0.006	0.005	0.024	0.020	0.038	0.021
30 years (2012-2041)	0.076	0.064	0.077	0.064	68.51		0.001	0.003	0.003	0.003	0.003	0.016	0.011	0.022	0.012	0.003	0.003	0.003	0.003	0.014	0.012	0.022	0.013

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results : NH New Hampshire

Page One of Two

State NH

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.055	0.048	0.060	0.045														0.042	0.043	0.041	0.045
2012	0.057	0.049	0.065	0.049	37.50	0.00	18.75	0.006	0.007	0.011	0.006	$0.00						0.042	0.043	0.041	0.045
2013	0.059	0.051	0.064	0.051	36.76	0.00	18.38	0.006	0.007	0.011	0.007	$0.00	0.006	0.007	0.012	0.007	$0.00	0.042	0.043	0.041	0.045
2014	0.061	0.053	0.066	0.052	36.76	0.00	18.38	0.006	0.007	0.012	0.007	$0.00	0.006	0.007	0.012	0.007	$0.00	0.042	0.043	0.041	0.045
2015	0.067	0.058	0.071	0.056	36.76	0.00	18.38	0.006	0.008	0.012	0.007	$0.00	0.006	0.008	0.013	0.007	$0.00	0.042	0.043	0.041	0.045
2016	0.067	0.058	0.074	0.057	15.09	18.01	16.55	0.006	0.007	0.012	0.007	$10.72	0.006	0.008	0.014	0.007	$10.72	0.042	0.043	0.041	0.045
2017	0.068	0.060	0.073	0.057	22.21	26.54	24.37	0.006	0.007	0.012	0.007	$10.80	0.006	0.007	0.013	0.007	$10.80	0.042	0.043	0.041	0.045
2018	0.073	0.065	0.080	0.063	31.01	37.09	34.05	0.006	0.008	0.014	0.007	$10.88	0.006	0.008	0.014	0.008	$10.88	0.035	0.036	0.034	0.037
2019	0.072	0.066	0.079	0.063	34.80	41.66	38.23	0.006	0.008	0.013	0.007	$10.51	0.007	0.008	0.014	0.008	$10.51	0.034	0.034	0.033	0.035
2020	0.074	0.065	0.081	0.064	48.69	58.34	53.52	0.003	0.004	0.006	0.004	$3.51	0.003	0.008	0.013	0.008	$3.51	0.032	0.033	0.031	0.034
2021	0.076	0.067	0.083	0.065	49.61	59.51	54.56	0.003	0.004	0.006	0.003	$3.54	0.003	0.004	0.007	0.004	$3.54	0.030	0.031	0.030	0.032
2022	0.079	0.070	0.086	0.068	74.46	89.42	81.94	0.003	0.003	0.005	0.003	$35.69	0.003	0.004	0.006	0.004	$35.69	0.029	0.029	0.028	0.030
2023	0.084	0.074	0.092	0.073	89.72	107.86	98.79	0.003	0.003	0.005	0.003	$17.63	0.003	0.004	0.006	0.003	$17.63	0.027	0.028	0.026	0.029
2024	0.087	0.076	0.093	0.075	98.16	118.14	108.15	0.002	0.003	0.004	0.003	$8.45	0.002	0.003	0.005	0.003	$8.45	0.025	0.026	0.025	0.027
2025	0.088	0.077	0.094	0.076	101.86	122.72	112.29					$4.31					$4.31	0.024	0.024	0.023	0.025
2026	0.088	0.076	0.093	0.076	104.09	125.53	114.81					$1.86					$1.86	0.022	0.023	0.022	0.023
2027	0.091	0.078	0.094	0.078	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.093	0.080	0.096	0.080	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.096	0.082	0.098	0.082	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.099	0.084	0.100	0.084	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.102	0.086	0.102	0.086	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.105	0.088	0.105	0.089	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.108	0.090	0.107	0.092	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.112	0.092	0.109	0.094	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.115	0.095	0.111	0.097	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.118	0.097	0.114	0.100	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.122	0.100	0.116	0.103	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.126	0.102	0.119	0.106	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.130	0.105	0.121	0.109	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.134	0.107	0.124	0.112	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.138	0.110	0.126	0.115	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.067	0.059	0.073	0.057	34.73	22.58	28.65	0.005	0.007	0.011	0.006	4.82	0.005	0.007	0.011	0.006	4.94	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.072	0.064	0.078	0.062	51.93	48.94	50.44	0.004	0.005	0.009	0.005	7.51	0.004	0.005	0.009	0.005	7.70	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.088	0.075	0.091	0.075	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Page Two of Two

Zone: NH

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.049	0.042	0.053	0.039	43.20		0.0019																
2012	0.050	0.043	0.057	0.042	34.72	16.6%	0.0021	0.006	0.007	0.011	0.006	0.035	0.025	0.048	0.027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.051	0.045	0.056	0.044	34.04	15.7%	0.0026	0.006	0.007	0.011	0.007	0.035	0.026	0.049	0.028	0.006	0.007	0.012	0.007	0.036	0.027	0.050	0.029
2014	0.053	0.046	0.057	0.045	34.04	17.7%	0.0029	0.006	0.007	0.012	0.007	0.036	0.026	0.051	0.028	0.006	0.007	0.012	0.007	0.037	0.027	0.052	0.029
2015	0.058	0.050	0.062	0.048	34.04	15.9%	0.0033	0.006	0.008	0.012	0.007	0.040	0.029	0.054	0.031	0.006	0.008	0.013	0.007	0.040	0.030	0.056	0.032
2016	0.058	0.050	0.064	0.049	13.98	16.0%	0.0037	0.006	0.007	0.012	0.007	0.038	0.027	0.056	0.030	0.006	0.008	0.014	0.007	0.040	0.030	0.060	0.032
2017	0.058	0.051	0.063	0.049	20.56	16.2%	0.0040	0.006	0.007	0.012	0.007	0.038	0.028	0.055	0.029	0.006	0.007	0.013	0.007	0.038	0.029	0.057	0.030
2018	0.064	0.057	0.070	0.055	28.72	16.3%	0.0026	0.006	0.008	0.014	0.007	0.042	0.031	0.062	0.033	0.006	0.008	0.014	0.008	0.042	0.032	0.064	0.034
2019	0.065	0.059	0.072	0.057	32.22	16.4%	0.0010	0.006	0.008	0.013	0.007	0.041	0.032	0.060	0.033	0.007	0.008	0.014	0.008	0.042	0.032	0.062	0.034
2020	0.067	0.059	0.073	0.057	45.08	16.5%	0.0013	0.003	0.004	0.006	0.004	0.021	0.016	0.028	0.017	0.003	0.008	0.013	0.008	0.021	0.032	0.058	0.034
2021	0.069	0.061	0.076	0.059	45.94	16.6%	0.0007	0.003	0.004	0.006	0.003	0.019	0.014	0.026	0.015	0.003	0.004	0.007	0.004	0.020	0.016	0.029	0.017
2022	0.071	0.063	0.077	0.061	68.95	16.8%	0.0015	0.003	0.003	0.005	0.003	0.017	0.013	0.023	0.014	0.003	0.004	0.006	0.004	0.018	0.015	0.027	0.016
2023	0.075	0.065	0.082	0.064	83.08	16.9%	0.0023	0.003	0.003	0.005	0.003	0.016	0.012	0.021	0.013	0.003	0.004	0.006	0.003	0.016	0.014	0.025	0.015
2024	0.078	0.067	0.083	0.066	90.89	17.0%	0.0025	0.002	0.003	0.004	0.003	0.014	0.010	0.018	0.011	0.002	0.003	0.005	0.003	0.014	0.012	0.022	0.013
2025	0.079	0.068	0.084	0.068	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.004	0.003	0.000	0.011	0.019	0.012
2026	0.080	0.069	0.084	0.068	96.38	17.3%	0.0011	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.082	0.071	0.086	0.070	97.20	17.4%	0.0009																
2028	0.085	0.073	0.088	0.072	97.68	17.5%	0.0007																
2029	0.088	0.074	0.090	0.074	97.80	17.7%	0.0006																
2030	0.090	0.076	0.091	0.077	97.92	17.8%	0.0005																
2031	0.093	0.078	0.093	0.079	98.04	17.9%	0.0005																
2032	0.096	0.080	0.095	0.081	98.04	18.1%	0.0005																
2033	0.099	0.082	0.097	0.083	98.04	18.2%	0.0005																
2034	0.102	0.084	0.100	0.086	98.04	18.3%	0.0005																
2035	0.105	0.086	0.102	0.088	98.04	18.5%	0.0005																
2036	0.108	0.089	0.104	0.091	98.04	18.6%	0.0005																
2037	0.111	0.091	0.106	0.094	98.04	18.7%	0.0005																
2038	0.115	0.093	0.108	0.096	98.04	18.9%	0.0005																
2039	0.118	0.095	0.111	0.099	98.04	19.0%	0.0005																
2040	0.122	0.098	0.113	0.102	98.04	19.1%	0.0005																
2041	0.126	0.100	0.115	0.105	98.04	19.3%	0.0005																

Levelized Cos																							
10 years (2012-2021)	0.059	0.052	0.065	0.050	32.15		0.002	0.005	0.007	0.011	0.006	0.035	0.026	0.049	0.027	0.005	0.007	0.011	0.006	0.032	0.025	0.048	0.027
15 years (2012-2026)	0.064	0.056	0.070	0.055	48.09		0.002	0.004	0.005	0.009	0.005	0.027	0.020	0.039	0.022	0.004	0.006	0.009	0.005	0.025	0.021	0.040	0.022
30 years (2012-2041)	0.079	0.067	0.082	0.067	68.51		0.002	0.003	0.003	0.005	0.003	0.016	0.012	0.023	0.013	0.002	0.003	0.005	0.003	0.015	0.012	0.023	0.013

NOTES: General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results : RI Rhode Island

State RI

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.054	0.046	0.059	0.043														0.042	0.043	0.041	0.045
2012	0.056	0.048	0.066	0.047	37.50	*0.00*	18.75	0.009	0.007	0.010	0.005	$0.00						0.042	0.043	0.041	0.045
2013	0.057	0.050	0.068	0.049	36.76	*0.00*	18.38	0.009	0.007	0.010	0.005	$0.00	0.009	0.007	0.010	0.006	$0.00	0.042	0.043	0.041	0.045
2014	0.059	0.052	0.071	0.051	36.76	*0.00*	18.38	0.009	0.007	0.010	0.005	$0.00	0.009	0.007	0.010	0.005	$0.00	0.042	0.043	0.041	0.045
2015	0.066	0.057	0.077	0.056	36.76	0.00	18.38	0.010	0.008	0.010	0.006	$0.00	0.010	0.008	0.011	0.006	$0.00	0.042	0.043	0.041	0.045
2016	0.066	0.058	0.084	0.057	15.09	18.01	16.55	0.009	0.007	0.011	0.005	$13.79	0.010	0.008	0.011	0.006	$13.79	0.042	0.043	0.041	0.045
2017	0.067	0.059	0.084	0.057	22.21	26.54	24.37	0.009	0.007	0.010	0.005	$13.83	0.009	0.007	0.011	0.005	$13.83	0.042	0.043	0.041	0.045
2018	0.066	0.058	0.085	0.056	31.01	37.09	34.05	0.009	0.007	0.010	0.005	$13.89	0.009	0.007	0.011	0.005	$13.89	0.042	0.043	0.041	0.045
2019	0.064	0.057	0.081	0.055	34.80	41.66	38.23	0.009	0.007	0.010	0.005	$13.33	0.009	0.007	0.010	0.005	$13.33	0.042	0.043	0.041	0.045
2020	0.065	0.054	0.074	0.055	48.69	58.34	53.52	0.004	0.003	0.005	0.003	$4.43	0.004	0.007	0.009	0.005	$4.43	0.042	0.043	0.041	0.045
2021	0.065	0.055	0.074	0.055	49.61	59.51	54.56	0.004	0.003	0.004	0.002	$4.46	0.004	0.003	0.005	0.003	$4.46	0.042	0.043	0.041	0.045
2022	0.066	0.055	0.074	0.055	74.46	89.42	81.94	0.003	0.003	0.004	0.002	$44.79	0.004	0.003	0.004	0.002	$44.79	0.042	0.043	0.041	0.045
2023	0.069	0.057	0.076	0.058	89.72	107.86	98.79	0.003	0.002	0.003	0.002	$22.05	0.003	0.003	0.004	0.002	$22.05	0.042	0.043	0.041	0.045
2024	0.071	0.057	0.078	0.059	98.16	118.14	108.15	0.003	0.002	0.003	0.002	$10.53	0.003	0.002	0.003	0.002	$10.53	0.042	0.043	0.041	0.045
2025	0.070	0.056	0.077	0.059	101.86	122.72	112.29					$5.35					$5.35	0.042	0.043	0.041	0.045
2026	0.071	0.056	0.079	0.059	104.09	125.53	114.81					$2.34					$2.34	0.042	0.043	0.041	0.045
2027	0.072	0.057	0.082	0.060	104.98	126.75	115.86											0.042	0.043	0.041	0.045
2028	0.075	0.059	0.084	0.062	105.49	127.51	116.50											0.042	0.043	0.041	0.045
2029	0.077	0.060	0.086	0.064	105.62	127.81	116.72											0.042	0.043	0.041	0.045
2030	0.079	0.062	0.089	0.065	105.75	128.11	116.93											0.042	0.043	0.041	0.045
2031	0.081	0.064	0.091	0.067	105.88	128.41	117.15											0.042	0.043	0.041	0.045
2032	0.083	0.066	0.094	0.069	105.88	128.55	117.22											0.042	0.043	0.041	0.045
2033	0.086	0.068	0.097	0.071	105.88	128.70	117.29											0.042	0.043	0.041	0.045
2034	0.088	0.070	0.100	0.073	105.88	128.84	117.36											0.042	0.043	0.041	0.045
2035	0.091	0.072	0.102	0.076	105.88	128.99	117.43											0.042	0.043	0.041	0.045
2036	0.094	0.074	0.105	0.078	105.88	129.13	117.51											0.042	0.043	0.041	0.045
2037	0.096	0.076	0.109	0.080	105.88	129.28	117.58											0.042	0.043	0.041	0.045
2038	0.099	0.078	0.112	0.082	105.88	129.43	117.65											0.042	0.043	0.041	0.045
2039	0.102	0.081	0.115	0.085	105.88	129.57	117.73											0.042	0.043	0.041	0.045
2040	0.105	0.083	0.118	0.087	105.88	129.72	117.80											0.042	0.043	0.041	0.045
2041	0.108	0.085	0.122	0.090	105.88	129.87	117.88											0.042	0.043	0.041	0.045

Levelized Costs																					
10 years (2012-2021)	0.063	0.055	0.076	0.053	34.73	22.58	28.65	0.008	0.006	0.009	0.005	6.15	0.008	0.006	0.009	0.005	6.30	0.042	0.043	0.041	0.045
15 years (2012-2026)	0.065	0.055	0.076	0.055	51.93	48.94	50.44	0.006	0.005	0.007	0.004	9.48	0.006	0.005	0.007	0.004	9.72	0.042	0.043	0.041	0.045
30 years (2012-2041)	0.074	0.061	0.086	0.062	73.99	81.60	77.80											0.042	0.043	0.041	0.045

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: RI

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.049	0.042	0.054	0.039	43.20		0.0006
2012	0.050	0.043	0.060	0.042	34.72	16.6%	0.0009
2013	0.051	0.045	0.061	0.044	34.04	15.7%	0.0013
2014	0.053	0.046	0.064	0.045	34.04	17.7%	0.0016
2015	0.058	0.051	0.068	0.049	34.04	15.9%	0.0020
2016	0.058	0.051	0.074	0.050	13.98	16.0%	0.0024
2017	0.059	0.052	0.074	0.049	20.56	16.2%	0.0028
2018	0.059	0.051	0.076	0.050	28.72	16.3%	0.0019
2019	0.058	0.052	0.074	0.050	32.22	16.4%	0.0008
2020	0.058	0.049	0.067	0.049	45.08	16.5%	0.0010
2021	0.059	0.050	0.068	0.050	45.94	16.6%	0.0005
2022	0.059	0.049	0.067	0.050	68.95	16.8%	0.0010
2023	0.062	0.051	0.069	0.051	83.08	16.9%	0.0015
2024	0.063	0.051	0.070	0.052	90.89	17.0%	0.0016
2025	0.063	0.050	0.070	0.053	94.32	17.1%	0.0012
2026	0.064	0.051	0.072	0.053	96.38	17.3%	0.0006
2027	0.066	0.052	0.074	0.055	97.20	17.4%	0.0005
2028	0.068	0.054	0.076	0.056	97.68	17.5%	0.0004
2029	0.070	0.055	0.079	0.058	97.80	17.7%	0.0004
2030	0.072	0.057	0.081	0.060	97.92	17.8%	0.0003
2031	0.074	0.058	0.083	0.061	98.04	17.9%	0.0003
2032	0.076	0.060	0.086	0.063	98.04	18.1%	0.0003
2033	0.079	0.062	0.088	0.065	98.04	18.2%	0.0003
2034	0.081	0.064	0.091	0.067	98.04	18.3%	0.0003
2035	0.083	0.066	0.094	0.069	98.04	18.5%	0.0003
2036	0.086	0.068	0.096	0.071	98.04	18.6%	0.0003
2037	0.088	0.070	0.099	0.073	98.04	18.7%	0.0003
2038	0.091	0.072	0.102	0.075	98.04	18.9%	0.0003
2039	0.093	0.074	0.105	0.077	98.04	19.0%	0.0003
2040	0.096	0.076	0.108	0.080	98.04	19.1%	0.0003
2041	0.099	0.078	0.111	0.082	98.04	19.3%	0.0003
Levelized Cos							
10 years (2012-2021)	0.056	0.049	0.068	0.048	32.15		0.002
15 years (2012-2026)	0.058	0.049	0.069	0.049	48.09		0.001
30 years (2012-2041)	0.067	0.055	0.078	0.056	68.51		0.001

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2012	0.009	0.007	0.010	0.005	0.034	0.025	0.047	0.027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.009	0.007	0.010	0.005	0.035	0.026	0.048	0.028	0.009	0.007	0.010	0.006	0.036	0.026	0.050	0.029
2014	0.009	0.007	0.010	0.005	0.036	0.026	0.051	0.028	0.009	0.007	0.010	0.005	0.036	0.027	0.052	0.029
2015	0.010	0.008	0.010	0.006	0.039	0.029	0.054	0.031	0.010	0.008	0.011	0.006	0.040	0.029	0.055	0.032
2016	0.009	0.007	0.011	0.005	0.037	0.027	0.055	0.029	0.010	0.008	0.011	0.006	0.040	0.029	0.060	0.032
2017	0.009	0.007	0.010	0.005	0.037	0.028	0.055	0.029	0.009	0.007	0.011	0.005	0.038	0.028	0.056	0.030
2018	0.009	0.007	0.010	0.005	0.037	0.027	0.056	0.029	0.009	0.007	0.011	0.005	0.038	0.028	0.057	0.030
2019	0.009	0.007	0.010	0.005	0.036	0.027	0.054	0.029	0.009	0.007	0.010	0.005	0.037	0.028	0.055	0.029
2020	0.004	0.003	0.005	0.003	0.018	0.013	0.024	0.014	0.004	0.007	0.009	0.005	0.018	0.026	0.050	0.029
2021	0.004	0.003	0.004	0.002	0.016	0.012	0.022	0.013	0.004	0.003	0.005	0.003	0.017	0.013	0.025	0.014
2022	0.003	0.003	0.004	0.002	0.015	0.010	0.019	0.011	0.004	0.003	0.004	0.002	0.015	0.012	0.022	0.013
2023	0.003	0.002	0.003	0.002	0.013	0.009	0.017	0.010	0.003	0.003	0.004	0.002	0.013	0.011	0.020	0.012
2024	0.003	0.002	0.003	0.002	0.011	0.008	0.015	0.009	0.003	0.002	0.003	0.002	0.012	0.009	0.018	0.010
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.003	0.002	0.000	0.008	0.015	0.009
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Levelized Cos																
10 years (2012-2021)	0.008	0.006	0.009	0.005	0.033	0.024	0.047	0.026	0.007	0.006	0.009	0.005	0.030	0.023	0.046	0.025
15 years (2012-2026)	0.006	0.005	0.007	0.004	0.026	0.019	0.036	0.020	0.006	0.005	0.007	0.004	0.023	0.019	0.037	0.020
30 years (2012-2041)	0.004	0.003	0.004	0.002	0.015	0.011	0.021	0.012	0.003	0.003	0.004	0.002	0.014	0.011	0.022	0.012

NOTES: General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results : VT Vermont

Page One of Two

State VT

User-defined Inputs			
Wholesale Risk Premium (WRP)	11%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.056	0.047	0.062	0.045														0.042	0.043	0.041	0.045
2012	0.057	0.048	0.068	0.048	37.50	0.00	18.75	0.001	0.001	0.002	0.001	$0.00						0.042	0.043	0.041	0.045
2013	0.059	0.051	0.070	0.050	36.76	0.00	18.38	0.002	0.001	0.003	0.001	$0.00	0.002	0.002	0.003	0.002	$0.00	0.042	0.043	0.041	0.045
2014	0.061	0.053	0.073	0.051	36.76	0.00	18.38	0.002	0.001	0.003	0.001	$0.00	0.002	0.002	0.003	0.001	$0.00	0.042	0.043	0.041	0.045
2015	0.067	0.057	0.079	0.056	36.76	0.00	18.38	0.002	0.002	0.003	0.002	$0.00	0.002	0.002	0.003	0.002	$0.00	0.042	0.043	0.041	0.045
2016	0.068	0.058	0.086	0.057	15.09	18.36	16.73	0.002	0.001	0.003	0.001	$3.27	0.002	0.002	0.003	0.002	$3.27	0.042	0.043	0.041	0.045
2017	0.068	0.059	0.086	0.057	22.21	27.05	24.63	0.002	0.001	0.003	0.001	$3.27	0.002	0.002	0.003	0.001	$3.27	0.042	0.043	0.041	0.045
2018	0.074	0.066	0.096	0.064	31.01	37.81	34.41	0.002	0.002	0.003	0.002	$3.28	0.002	0.002	0.003	0.002	$3.28	0.035	0.036	0.034	0.037
2019	0.075	0.067	0.094	0.065	34.80	42.46	38.63	0.002	0.002	0.003	0.002	$3.14	0.002	0.002	0.003	0.002	$3.14	0.034	0.034	0.033	0.035
2020	0.077	0.067	0.090	0.066	48.69	59.47	54.08	0.001	0.001	0.001	0.001	$1.04	0.001	0.002	0.003	0.002	$1.04	0.032	0.033	0.031	0.034
2021	0.079	0.069	0.091	0.067	49.61	60.66	55.13	0.001	0.001	0.001	0.001	$1.05	0.001	0.001	0.001	0.001	$1.05	0.030	0.031	0.030	0.032
2022	0.081	0.071	0.093	0.070	74.46	91.14	82.80	0.001	0.001	0.001	0.001	$10.52	0.001	0.001	0.001	0.001	$10.52	0.029	0.029	0.028	0.030
2023	0.086	0.075	0.098	0.074	89.72	109.94	99.83	0.001	0.001	0.001	0.001	$5.18	0.001	0.001	0.001	0.001	$5.18	0.027	0.028	0.026	0.029
2024	0.089	0.077	0.099	0.075	98.16	120.41	109.29	0.001	0.001	0.001	0.001	$2.47	0.001	0.001	0.001	0.001	$2.47	0.025	0.026	0.025	0.027
2025	0.090	0.078	0.100	0.078	101.86	125.08	113.47					$1.25					$1.25	0.024	0.024	0.023	0.025
2026	0.092	0.079	0.104	0.078	104.09	127.95	116.02					$0.54					$0.54	0.022	0.023	0.022	0.023
2027	0.094	0.081	0.107	0.081	104.98	129.19	117.08											0.022	0.023	0.022	0.023
2028	0.097	0.084	0.110	0.083	105.49	129.97	117.73											0.022	0.023	0.022	0.023
2029	0.100	0.086	0.113	0.085	105.62	130.27	117.95											0.022	0.023	0.022	0.023
2030	0.103	0.088	0.116	0.088	105.75	130.58	118.17											0.022	0.023	0.022	0.023
2031	0.107	0.091	0.119	0.091	105.88	130.88	118.38											0.022	0.023	0.022	0.023
2032	0.110	0.093	0.123	0.093	105.88	131.03	118.46											0.022	0.023	0.022	0.023
2033	0.113	0.096	0.126	0.096	105.88	131.17	118.53											0.022	0.023	0.022	0.023
2034	0.117	0.098	0.130	0.099	105.88	131.32	118.60											0.022	0.023	0.022	0.023
2035	0.120	0.101	0.133	0.102	105.88	131.47	118.68											0.022	0.023	0.022	0.023
2036	0.124	0.104	0.137	0.105	105.88	131.62	118.75											0.022	0.023	0.022	0.023
2037	0.128	0.106	0.141	0.108	105.88	131.77	118.83											0.022	0.023	0.022	0.023
2038	0.132	0.109	0.145	0.112	105.88	131.92	118.90											0.022	0.023	0.022	0.023
2039	0.136	0.112	0.149	0.115	105.88	132.07	118.98											0.022	0.023	0.022	0.023
2040	0.140	0.115	0.153	0.119	105.88	132.22	119.05											0.022	0.023	0.022	0.023
2041	0.145	0.119	0.157	0.122	105.88	132.37	119.13											0.022	0.023	0.022	0.023

Levelized Costs																					
10 years (2012-2021)	0.068	0.059	0.083	0.058	34.73	23.01	28.87	0.002	0.001	0.002	0.001	1.45	0.001	0.001	0.002	0.001	1.49	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.074	0.064	0.087	0.063	51.93	49.88	50.91	0.001	0.001	0.002	0.001	2.23	0.001	0.001	0.002	0.001	2.29	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.091	0.078	0.104	0.077	73.99	83.17	78.58											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: VT

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.050	0.042	0.056	0.040	43.20		0.0000																
2012	0.052	0.044	0.061	0.043	34.72	16.6%	0.0000	0.001	0.001	0.002	0.001	0.036	0.026	0.050	0.029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.053	0.046	0.063	0.045	34.04	15.7%	0.0002	0.002	0.001	0.003	0.001	0.036	0.027	0.051	0.029	0.002	0.002	0.003	0.002	0.037	0.028	0.052	0.030
2014	0.054	0.047	0.066	0.046	34.04	17.7%	0.0005	0.002	0.001	0.003	0.001	0.037	0.027	0.052	0.029	0.002	0.002	0.003	0.001	0.038	0.028	0.054	0.030
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0007	0.002	0.002	0.003	0.002	0.041	0.030	0.056	0.032	0.002	0.002	0.003	0.002	0.042	0.031	0.058	0.033
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0010	0.002	0.001	0.003	0.001	0.039	0.028	0.058	0.031	0.002	0.002	0.003	0.002	0.042	0.031	0.062	0.033
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0013	0.002	0.001	0.003	0.001	0.039	0.029	0.057	0.030	0.002	0.002	0.003	0.001	0.040	0.030	0.059	0.031
2018	0.066	0.058	0.085	0.057	28.72	16.3%	0.0008	0.002	0.002	0.003	0.002	0.043	0.032	0.064	0.034	0.002	0.002	0.003	0.002	0.043	0.033	0.066	0.035
2019	0.067	0.060	0.084	0.058	32.22	16.4%	0.0003	0.002	0.002	0.003	0.002	0.043	0.033	0.062	0.034	0.002	0.002	0.003	0.002	0.043	0.033	0.064	0.035
2020	0.069	0.060	0.080	0.059	45.08	16.5%	0.0004	0.001	0.001	0.001	0.001	0.022	0.016	0.029	0.017	0.001	0.002	0.003	0.002	0.022	0.033	0.060	0.035
2021	0.071	0.062	0.082	0.060	45.94	16.6%	0.0002	0.001	0.001	0.001	0.001	0.020	0.015	0.027	0.016	0.001	0.001	0.001	0.001	0.020	0.017	0.030	0.018
2022	0.073	0.064	0.083	0.062	68.95	16.8%	0.0004	0.001	0.001	0.001	0.001	0.018	0.014	0.024	0.015	0.001	0.001	0.001	0.001	0.018	0.016	0.028	0.017
2023	0.077	0.067	0.087	0.066	83.08	16.9%	0.0005	0.001	0.001	0.001	0.001	0.017	0.012	0.022	0.013	0.001	0.001	0.001	0.001	0.017	0.014	0.026	0.015
2024	0.079	0.068	0.089	0.067	90.89	17.0%	0.0006	0.001	0.001	0.001	0.001	0.015	0.011	0.019	0.012	0.001	0.001	0.001	0.001	0.015	0.013	0.023	0.014
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.000	0.011	0.019	0.012
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.085	0.073	0.096	0.072	97.20	17.4%	0.0002																
2028	0.087	0.075	0.099	0.075	97.68	17.5%	0.0002																
2029	0.090	0.077	0.102	0.077	97.80	17.7%	0.0001																
2030	0.093	0.079	0.105	0.079	97.92	17.8%	0.0001																
2031	0.096	0.081	0.107	0.082	98.04	17.9%	0.0001																
2032	0.099	0.084	0.110	0.084	98.04	18.1%	0.0001																
2033	0.102	0.086	0.113	0.087	98.04	18.2%	0.0001																
2034	0.105	0.088	0.117	0.089	98.04	18.3%	0.0001																
2035	0.108	0.091	0.120	0.092	98.04	18.5%	0.0001																
2036	0.112	0.093	0.123	0.095	98.04	18.6%	0.0001																
2037	0.115	0.096	0.126	0.097	98.04	18.7%	0.0001																
2038	0.119	0.098	0.130	0.100	98.04	18.9%	0.0001																
2039	0.122	0.101	0.134	0.103	98.04	19.0%	0.0001																
2040	0.126	0.104	0.137	0.107	98.04	19.1%	0.0001																
2041	0.130	0.107	0.141	0.110	98.04	19.3%	0.0001																
Levelized Cos																							
10 years (2012-2021)	0.061	0.053	0.074	0.051	32.15		0.001	0.002	0.001	0.002	0.001	0.036	0.026	0.051	0.028	0.001	0.001	0.002	0.001	0.033	0.026	0.050	0.028
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.000	0.001	0.001	0.002	0.001	0.028	0.021	0.040	0.022	0.001	0.001	0.002	0.001	0.026	0.022	0.041	0.023
30 years (2012-2041)	0.082	0.070	0.094	0.069	68.51		0.000	0.001	0.001	0.001	0.001	0.017	0.012	0.024	0.013	0.001	0.001	0.001	0.001	0.015	0.013	0.024	0.014

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results : CT Connecticut (Statewide)

Page One of Two

State CT

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
					kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak				Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.048	0.064	0.046														0.042	0.043	0.041	0.045
2012	0.060	0.051	0.072	0.051	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.063	0.054	0.076	0.053	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.066	0.057	0.079	0.056	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.074	0.064	0.087	0.063	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.076	0.065	0.096	0.065	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.078	0.068	0.098	0.066	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.087	0.077	0.111	0.074	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.088	0.079	0.110	0.076	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.093	0.081	0.108	0.080	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.096	0.085	0.111	0.083	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.102	0.090	0.117	0.088	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.110	0.097	0.126	0.095	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.117	0.101	0.131	0.099	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.120	0.104	0.134	0.104	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.124	0.107	0.142	0.106	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.130	0.112	0.148	0.111	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.137	0.118	0.155	0.117	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.144	0.123	0.163	0.122	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.151	0.129	0.171	0.129	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.159	0.135	0.179	0.135	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.167	0.142	0.188	0.142	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.176	0.148	0.197	0.149	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.185	0.156	0.206	0.157	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.195	0.163	0.216	0.165	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.205	0.171	0.227	0.173	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.215	0.179	0.238	0.182	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.227	0.188	0.250	0.191	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.238	0.197	0.262	0.201	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.251	0.207	0.275	0.211	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.264	0.216	0.288	0.222	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.069	0.060	0.084	0.059	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.075	0.065	0.089	0.064	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.092	0.079	0.106	0.078	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Page Two of Two

Zone: CT

	Wholesale Avoided Costs of Electricity							2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity		Avoided REC Costs to Load	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.057	0.041	43.20		0.0016																
2012	0.053	0.045	0.064	0.045	35.41	16.6%	0.0019	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.055	0.047	0.067	0.047	35.41	15.7%	0.0022	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.058	0.050	0.070	0.049	36.12	17.7%	0.0025	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.065	0.056	0.077	0.055	36.84	15.9%	0.0029	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.067	0.057	0.085	0.056	15.43	16.0%	0.0033	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.068	0.059	0.086	0.057	23.16	16.2%	0.0037	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.077	0.068	0.099	0.065	32.99	16.3%	0.0028	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.079	0.071	0.099	0.068	37.75	16.4%	0.0017	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.083	0.072	0.097	0.071	53.88	16.5%	0.0022	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.087	0.076	0.101	0.074	56.00	16.6%	0.0014	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.091	0.080	0.105	0.078	85.73	16.8%	0.0023	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.098	0.085	0.112	0.084	105.36	16.9%	0.0032	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.104	0.090	0.117	0.088	117.58	17.0%	0.0033	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.107	0.092	0.120	0.092	124.45	17.1%	0.0027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.112	0.097	0.128	0.096	129.71	17.3%	0.0017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.118	0.102	0.134	0.100	133.43	17.4%	0.0015																
2028	0.124	0.107	0.141	0.106	136.78	17.5%	0.0014																
2029	0.131	0.112	0.148	0.111	139.68	17.7%	0.0013																
2030	0.137	0.117	0.155	0.117	142.65	17.8%	0.0012																
2031	0.145	0.123	0.163	0.123	145.68	17.9%	0.0012																
2032	0.152	0.129	0.171	0.129	148.60	18.1%	0.0012																
2033	0.160	0.135	0.179	0.136	151.57	18.2%	0.0012																
2034	0.169	0.142	0.188	0.143	154.60	18.3%	0.0012																
2035	0.177	0.148	0.197	0.150	157.69	18.5%	0.0012																
2036	0.187	0.156	0.207	0.158	160.85	18.6%	0.0013																
2037	0.196	0.163	0.217	0.166	164.06	18.7%	0.0013																
2038	0.207	0.171	0.228	0.174	167.34	18.9%	0.0013																
2039	0.217	0.179	0.239	0.183	170.69	19.0%	0.0013																
2040	0.229	0.188	0.251	0.193	174.10	19.1%	0.0014																
2041	0.241	0.197	0.263	0.203	177.59	19.3%	0.0014																

Levelized Cos																							
10 years (2012-2021)	0.061	0.053	0.075	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.066	0.058	0.079	0.056	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.083	0.071	0.095	0.070	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General
All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results : CT-NS Norwalk/Stamford

Page One of Two

State CT

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.061	0.052	0.073	0.051	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.063	0.055	0.077	0.054	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.067	0.058	0.080	0.057	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.075	0.064	0.088	0.063	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.077	0.066	0.097	0.066	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.079	0.069	0.099	0.066	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.088	0.078	0.112	0.075	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.089	0.080	0.111	0.077	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.094	0.082	0.109	0.080	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.097	0.086	0.113	0.083	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.103	0.091	0.118	0.089	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.112	0.098	0.127	0.096	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.118	0.102	0.132	0.100	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.121	0.105	0.135	0.105	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.125	0.109	0.143	0.107	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.132	0.114	0.150	0.112	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.138	0.119	0.157	0.118	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.145	0.124	0.164	0.124	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.153	0.130	0.172	0.130	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.161	0.136	0.181	0.136	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.169	0.143	0.190	0.143	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.178	0.150	0.199	0.151	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.187	0.157	0.209	0.158	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.197	0.165	0.219	0.167	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.207	0.173	0.229	0.175	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.218	0.181	0.241	0.184	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.229	0.190	0.252	0.193	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.241	0.199	0.265	0.203	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.254	0.209	0.278	0.214	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.267	0.219	0.291	0.225	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.060	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.066	0.090	0.065	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-NS

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.054	0.045	0.065	0.045	35.41	16.6%	0.0019	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.056	0.048	0.068	0.047	35.41	15.7%	0.0022	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.059	0.051	0.071	0.049	36.12	17.7%	0.0025	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.066	0.056	0.078	0.055	36.84	15.9%	0.0029	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.067	0.057	0.086	0.057	15.43	16.0%	0.0033	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.069	0.060	0.087	0.057	23.16	16.2%	0.0037	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.078	0.068	0.100	0.066	32.99	16.3%	0.0028	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.080	0.072	0.100	0.069	37.75	16.4%	0.0017	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.084	0.073	0.098	0.072	53.88	16.5%	0.0022	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.088	0.077	0.102	0.075	56.00	16.6%	0.0014	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.092	0.081	0.106	0.079	85.73	16.8%	0.0023	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.099	0.086	0.113	0.085	105.36	16.9%	0.0032	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.105	0.090	0.118	0.089	117.58	17.0%	0.0033	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.108	0.093	0.122	0.093	124.45	17.1%	0.0027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.113	0.098	0.130	0.097	129.71	17.3%	0.0017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.119	0.103	0.136	0.102	133.43	17.4%	0.0015																
2028	0.125	0.108	0.143	0.107	136.78	17.5%	0.0014																
2029	0.132	0.113	0.150	0.112	139.68	17.7%	0.0013																
2030	0.139	0.118	0.157	0.118	142.65	17.8%	0.0012																
2031	0.146	0.124	0.165	0.124	145.68	17.9%	0.0012																
2032	0.154	0.130	0.173	0.130	148.60	18.1%	0.0012																
2033	0.162	0.136	0.181	0.137	151.57	18.2%	0.0012																
2034	0.170	0.143	0.190	0.144	154.60	18.3%	0.0012																
2035	0.179	0.150	0.199	0.152	157.69	18.5%	0.0012																
2036	0.189	0.157	0.209	0.159	160.85	18.6%	0.0013																
2037	0.198	0.165	0.219	0.168	164.06	18.7%	0.0013																
2038	0.209	0.173	0.230	0.176	167.34	18.9%	0.0013																
2039	0.220	0.181	0.242	0.185	170.69	19.0%	0.0013																
2040	0.231	0.190	0.253	0.195	174.10	19.1%	0.0014																
2041	0.243	0.199	0.266	0.205	177.59	19.3%	0.0014																
Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results : CT-R Page One of Two

State CT

Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.048	0.064	0.046														0.042	0.043	0.041	0.045
2012	0.060	0.050	0.071	0.050	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.062	0.054	0.075	0.053	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.066	0.057	0.079	0.055	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.073	0.063	0.086	0.062	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.076	0.065	0.096	0.064	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.078	0.068	0.097	0.065	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.086	0.076	0.110	0.074	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.087	0.078	0.109	0.076	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.092	0.080	0.107	0.079	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.095	0.084	0.110	0.082	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.101	0.089	0.116	0.087	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.109	0.096	0.124	0.094	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.115	0.100	0.129	0.098	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.119	0.103	0.133	0.103	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.123	0.106	0.140	0.105	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.129	0.111	0.147	0.110	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.135	0.116	0.154	0.115	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.142	0.122	0.161	0.121	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.150	0.128	0.169	0.127	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.157	0.134	0.177	0.134	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.165	0.140	0.186	0.141	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.174	0.147	0.195	0.148	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.183	0.154	0.204	0.155	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.193	0.161	0.214	0.163	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.203	0.169	0.225	0.171	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.213	0.177	0.236	0.180	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.224	0.186	0.247	0.189	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.236	0.195	0.259	0.199	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.248	0.204	0.272	0.209	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.261	0.214	0.285	0.220	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.069	0.060	0.083	0.058	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.074	0.064	0.088	0.063	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.091	0.078	0.105	0.078	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Page Two of Two

Zone: CT-R

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.050	0.042	0.057	0.040	43.20		0.0016																
2012	0.053	0.044	0.063	0.044	35.41	16.6%	0.0019	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.055	0.047	0.067	0.046	35.41	15.7%	0.0022	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.058	0.050	0.070	0.048	36.12	17.7%	0.0025	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.064	0.055	0.076	0.054	36.84	15.9%	0.0029	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.066	0.056	0.084	0.056	15.43	16.0%	0.0033	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.068	0.058	0.085	0.056	23.16	16.2%	0.0037	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.076	0.067	0.098	0.065	32.99	16.3%	0.0028	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.078	0.070	0.098	0.068	37.75	16.4%	0.0017	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.082	0.071	0.096	0.070	53.88	16.5%	0.0022	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.086	0.076	0.100	0.074	56.00	16.6%	0.0014	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.090	0.079	0.104	0.078	85.73	16.8%	0.0023	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.097	0.085	0.111	0.083	105.36	16.9%	0.0032	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.103	0.089	0.115	0.087	117.58	17.0%	0.0033	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.106	0.092	0.119	0.091	124.45	17.1%	0.0027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.111	0.096	0.127	0.095	129.71	17.3%	0.0017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.117	0.101	0.133	0.099	133.43	17.4%	0.0015																
2028	0.123	0.105	0.140	0.105	136.78	17.5%	0.0014																
2029	0.129	0.111	0.146	0.110	139.68	17.7%	0.0013																
2030	0.136	0.116	0.154	0.116	142.65	17.8%	0.0012																
2031	0.143	0.122	0.161	0.121	145.68	17.9%	0.0012																
2032	0.151	0.127	0.169	0.128	148.60	18.1%	0.0012																
2033	0.158	0.134	0.177	0.134	151.57	18.2%	0.0012																
2034	0.167	0.140	0.186	0.141	154.60	18.3%	0.0012																
2035	0.176	0.147	0.195	0.148	157.69	18.5%	0.0012																
2036	0.185	0.154	0.205	0.156	160.85	18.6%	0.0013																
2037	0.194	0.161	0.215	0.164	164.06	18.7%	0.0013																
2038	0.205	0.169	0.226	0.173	167.34	18.9%	0.0013																
2039	0.215	0.178	0.237	0.181	170.69	19.0%	0.0013																
2040	0.226	0.186	0.248	0.191	174.10	19.1%	0.0014																
2041	0.238	0.195	0.260	0.200	177.59	19.3%	0.0014																
Levelized Cos																							
10 years (2012-2021)	0.061	0.052	0.074	0.051	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.082	0.070	0.094	0.069	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results :

CT-SWe
Southwest Connecticut, excluding Norwalk/Stamford

State CT

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.061	0.051	0.072	0.051	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.063	0.055	0.076	0.054	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.067	0.058	0.080	0.056	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.075	0.064	0.088	0.063	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.077	0.066	0.097	0.066	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.079	0.069	0.099	0.066	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.087	0.077	0.112	0.075	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.089	0.080	0.111	0.077	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.094	0.082	0.109	0.080	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.097	0.086	0.112	0.083	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.103	0.091	0.118	0.089	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.111	0.097	0.127	0.096	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.118	0.102	0.132	0.100	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.121	0.105	0.135	0.105	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.125	0.108	0.143	0.107	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.131	0.113	0.150	0.112	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.138	0.119	0.157	0.118	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.145	0.124	0.164	0.124	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.153	0.130	0.172	0.130	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.160	0.136	0.181	0.136	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.169	0.143	0.189	0.143	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.178	0.150	0.199	0.151	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.187	0.157	0.208	0.158	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.196	0.165	0.219	0.166	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.207	0.173	0.229	0.175	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.217	0.181	0.240	0.184	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.229	0.190	0.252	0.193	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.241	0.199	0.265	0.203	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.253	0.208	0.277	0.213	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.266	0.218	0.291	0.224	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.059	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.075	0.066	0.090	0.064	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-SWe

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj
2011	0.051	0.043	0.058	0.041	43.20		0.0016								
2012	0.054	0.045	0.065	0.045	35.41	16.6%	0.0019	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020
2013	0.056	0.048	0.068	0.047	35.41	15.7%	0.0022	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021
2014	0.059	0.051	0.071	0.049	36.12	17.7%	0.0025	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022
2015	0.066	0.056	0.078	0.055	36.84	15.9%	0.0029	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024
2016	0.067	0.057	0.086	0.057	15.43	16.0%	0.0033	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023
2017	0.069	0.060	0.087	0.057	23.16	16.2%	0.0037	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024
2018	0.077	0.068	0.100	0.066	32.99	16.3%	0.0028	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027
2019	0.080	0.072	0.100	0.069	37.75	16.4%	0.0017	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028
2020	0.084	0.073	0.098	0.072	53.88	16.5%	0.0022	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014
2021	0.088	0.077	0.102	0.075	56.00	16.6%	0.0014	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013
2022	0.092	0.081	0.106	0.079	85.73	16.8%	0.0023	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012
2023	0.099	0.086	0.113	0.085	105.36	16.9%	0.0032	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012
2024	0.105	0.090	0.118	0.089	117.58	17.0%	0.0033	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010
2025	0.108	0.093	0.121	0.093	124.45	17.1%	0.0027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2026	0.113	0.098	0.129	0.096	129.71	17.3%	0.0017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.119	0.103	0.136	0.101	133.43	17.4%	0.0015								
2028	0.125	0.108	0.142	0.107	136.78	17.5%	0.0014								
2029	0.132	0.113	0.149	0.112	139.68	17.7%	0.0013								
2030	0.139	0.118	0.157	0.118	142.65	17.8%	0.0012								
2031	0.146	0.124	0.164	0.124	145.68	17.9%	0.0012								
2032	0.154	0.130	0.173	0.130	148.60	18.1%	0.0012								
2033	0.162	0.136	0.181	0.137	151.57	18.2%	0.0012								
2034	0.170	0.143	0.190	0.144	154.60	18.3%	0.0012								
2035	0.179	0.150	0.199	0.151	157.69	18.5%	0.0012								
2036	0.188	0.157	0.209	0.159	160.85	18.6%	0.0013								
2037	0.198	0.165	0.219	0.167	164.06	18.7%	0.0013								
2038	0.209	0.173	0.230	0.176	167.34	18.9%	0.0013								
2039	0.220	0.181	0.241	0.185	170.69	19.0%	0.0013								
2040	0.231	0.190	0.253	0.194	174.10	19.1%	0.0014								
2041	0.243	0.199	0.266	0.204	177.59	19.3%	0.0014								
Levelized Cos															
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009

	2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ak	al	am	an	ao	ap	aq	ar
2011								
2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Levelized Cos								
10 years (2012-2021)	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results :

State CT

CT-SWi
Southwest Connecticut, including Norwalk/Stamford

Page One of Two

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.061	0.051	0.072	0.051	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.063	0.055	0.076	0.054	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.067	0.058	0.080	0.057	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.075	0.064	0.088	0.063	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.077	0.066	0.097	0.066	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.079	0.069	0.099	0.066	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.088	0.078	0.112	0.075	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.089	0.080	0.111	0.077	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.094	0.082	0.109	0.080	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.097	0.086	0.113	0.083	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.103	0.091	0.118	0.089	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.112	0.097	0.127	0.096	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.118	0.102	0.132	0.100	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.121	0.105	0.135	0.105	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.125	0.108	0.143	0.107	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.131	0.113	0.150	0.112	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.138	0.119	0.157	0.118	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.145	0.124	0.164	0.124	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.153	0.130	0.172	0.130	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.160	0.136	0.181	0.136	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.169	0.143	0.189	0.143	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.178	0.150	0.199	0.151	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.187	0.157	0.208	0.158	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.197	0.165	0.219	0.166	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.207	0.173	0.229	0.175	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.218	0.181	0.240	0.184	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.229	0.190	0.252	0.193	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.241	0.199	0.265	0.203	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.253	0.208	0.278	0.214	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.267	0.219	0.291	0.224	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.059	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.066	0.090	0.065	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-SWi

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.054	0.045	0.065	0.045	35.41	16.6%	0.0019	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.056	0.048	0.068	0.047	35.41	15.7%	0.0022	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.059	0.051	0.071	0.049	36.12	17.7%	0.0025	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.066	0.056	0.078	0.055	36.84	15.9%	0.0029	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.067	0.057	0.086	0.057	15.43	16.0%	0.0033	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.069	0.060	0.087	0.057	23.16	16.2%	0.0037	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.077	0.068	0.100	0.066	32.99	16.3%	0.0028	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.080	0.072	0.100	0.069	37.75	16.4%	0.0017	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.084	0.073	0.098	0.072	53.88	16.5%	0.0022	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.088	0.077	0.102	0.075	56.00	16.6%	0.0014	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.092	0.081	0.106	0.079	85.73	16.8%	0.0023	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.099	0.086	0.113	0.085	105.36	16.9%	0.0032	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.105	0.090	0.118	0.089	117.58	17.0%	0.0033	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.108	0.093	0.121	0.093	124.45	17.1%	0.0027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.113	0.098	0.129	0.097	129.71	17.3%	0.0017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.119	0.103	0.136	0.101	133.43	17.4%	0.0015																
2028	0.125	0.108	0.142	0.107	136.78	17.5%	0.0014																
2029	0.132	0.113	0.149	0.112	139.68	17.7%	0.0013																
2030	0.139	0.118	0.157	0.118	142.65	17.8%	0.0012																
2031	0.146	0.124	0.165	0.124	145.68	17.9%	0.0012																
2032	0.154	0.130	0.173	0.130	148.60	18.1%	0.0012																
2033	0.162	0.136	0.181	0.137	151.57	18.2%	0.0012																
2034	0.170	0.143	0.190	0.144	154.60	18.3%	0.0012																
2035	0.179	0.150	0.199	0.151	157.69	18.5%	0.0012																
2036	0.188	0.157	0.209	0.159	160.85	18.6%	0.0013																
2037	0.198	0.165	0.219	0.167	164.06	18.7%	0.0013																
2038	0.209	0.173	0.230	0.176	167.34	18.9%	0.0013																
2039	0.220	0.181	0.241	0.185	170.69	19.0%	0.0013																
2040	0.231	0.190	0.253	0.195	174.10	19.1%	0.0014																
2041	0.243	0.199	0.266	0.205	177.59	19.3%	0.0014																

Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Appendix C: Selected Input Assumptions to Avoided Cost Analyses

Table of Exhibits

Discussion of EPA Regulations

The EPA is in the process of numerous rulemakings, many of them court-ordered, which implement statutory requirements under the Clean Air Act, Clean Water Act and Resource Conservation and Recovery Act (RCRA). Several of these rules will regulate the power sector directly. These include revisions of Clean Air Act new source performance standards for power plants, regulation of interstate pollutant emissions from power plants, regulation of hazardous air pollutant emissions from power plants, haze regulations, new standards governing cooling intake water, and new effluent limitation guidelines for wastewater discharges from power plants. In addition, EPA has proposed to regulate the disposal of coal combustion wastes for the first time. Finally, the EPA is in the process of revising several National Ambient Air Quality Standards (NAAQS) for pollutants including particulate matter (PM), ozone, sulfur dioxide, and nitrogen oxides. Revised NAAQS will result in the designation of additional nonattainment areas, which in turn will obligate states to require emissions reductions from major pollution sources including power plants.

When considered individually, these rules to varying extents will require retrofits and associated outages and may result in retirements and/or the repowering of existing electric generating units across the United States. Taken together, these rules will have a significant effect on the generating fleet. The following sections describe what are anticipated to be the most economically consequential rules, and summarize the analysis undertaken to date on the costs of these future regulations and associated impacts on the power sector. A summary of the timeline of regulations is provided in Appendix C.

Clean Air Transport Rule (CATR)

The Clean Air Transport Rule, proposed in July 2010, will reduce emissions that contribute to non-attainment of National Ambient Air Quality Standards or that interfere with maintenance of those standards by downwind states.[1] Based on the current proposal, emissions of sulfur dioxide and nitrogen oxide from electric generating units in 31 eastern states and the District of Columbia will be capped to help enable downwind states to comply with the NAAQS, including the annual $PM_{2.5}$ NAAQS (promulgated in 1997) and the 24 hour $PM_{2.5}$ NAAQS (promulgated in 2006).[2] Connecticut is covered for summer NOx emissions (for ozone) and year-round particulates, NOx and SO_2 (for $PM_{2.5}$), while Massachusetts is covered only for $PM_{2.5}$, and the other four New England

[1] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010 / Proposed Rules, pp. 45210 ff.

[2] US EPA, Office of Air and Radiation. *Proposed Air Pollution Transport Rule*. July 26, 2010. Slide 4. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf.

states are not covered.[3] Compliance with the transport rule will require substantial investments in scrubbers and other control devices at many generation stations.

The CATR sets limits on the emission of sulfur dioxide and nitrogen oxide that will become effective in two phases. Sulfur dioxide emissions are required to decline from 4.7 million tons in 2009 to 3.9 million tons by 2012, and then to 2.5 million tons by 2014, for a cumulative reduction of 47% over the five-year compliance period. The Rule is likely to have a minimal effect on nitrogen oxide emissions, however, because the rule's emission caps (1.4 million tons per year) are slightly higher than the actual nitrogen oxide emissions in the covered states in 2009.

In the July 2010 proposal, the EPA identified a "preferred approach" for the new regulations, but also took comments on two alternatives. All three approaches would cover the same geographic area, set a pollution limit (or budget) for each state, and obtain the mandated reductions from power plants. The EPA's preferred approach and the first alternative would both allow trading of emissions allowances among power plants within a state, with the preferred approach also allowing some limited trading among states. The third approach would allow averaging among a power plant owner's in-state generating units.[4]

To achieve the required emissions reductions, the EPA expects that power plants will "fuel switch" to lower-sulfur coal, operate already installed emissions control equipment more frequently, or install new pollution control equipment.[5] The EPA anticipates that a final rule will be issued in the spring of 2011.

The EPA estimates that the costs of compliance with the CATR are $2.8 billion in 2014. Estimates of the expected benefits from the proposed rule range between $120 and $290 billion in 2014. The EPA expects that electricity prices will increase by less than 2%, natural gas prices will increase by less than 1%, and coal use will be reduced by less than 1%.[6]

The EPA has also begun assessing the transport of air pollution across state boundaries that would interfere with attainment of the 2010 ozone standard. The Second Clean Air Transport Rule will address the responsibility of upwind states to downwind state ozone

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[3] Of the excluded states, only Maine and New Hampshire have power plants of the sort that would be affected by the rule.

[4] US EPA. *Proposed Transport Rule Would Reduce Interstate Transport of Ozone and Fine Particle Pollution*. Clean Air Transport Rule Fact Sheet. July 6, 2010. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf

[5] US EPA, Office of Air and Radiation. *Reducing Air Pollution from Power Plants*. September 24, 2010. Slide 10. Available at: http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20AIR%20Presentation%20Sept%2024%202010%20_%20Sam%20Napolitano.pdf

[6] US EPA, Office of Air and Radiation. *Proposed Air Pollution Transport Rule*. July 26, 2010. Slide 13. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf

problems under the Clean Air Act. The EPA is expected to propose the Second Clean Air Transport Rule in summer 2011, and promulgate a final rule in summer 2012.[7]

Air Toxics Standards (MACT Rule)

The EPA is under court order to set emission limits for hazardous air pollutant emissions from electric generating units under section 112(d) of the Clean Air Act. More than 180 hazardous air pollutants are listed under the Clean Air Act, and those most relevant to the electric power industry include mercury, dioxins, and acid gases. This "air toxics rule" would require that sources meet emission limits based on EPA's assessment of "Maximum Achievable Control Technology" or "MACT." For existing sources, this means that the level of control achieved must be in line with the average of the top twelve percent of top-performing power plants. Requirements for new sources are at least as stringent as the single best performing source, reflecting the maximum emissions reductions achievable with state-of-the-art pollution controls. Existing units will have three years to comply with the final rule once it is issued, while new sources will have to comply immediately upon issuance of the rule.[8] The EPA issued the new proposed rule in March 2011 and is expected to finalize the rule in November 2011.[9] New standards must be implemented within three years after the rule is finalized, so compliance by 2014 is implied.

The EPA has not yet released an analysis of costs and benefits of the MACT rule. However, as discussed below, several recent analyses assess their impact on the power sector.

Coal Combustion Residuals

Coal combustion residuals are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and flue gas materials. In 2008, annual production of these residuals was 136 million tons.[10] The spill of coal ash at the Tennessee Valley Authority's containment facility prompted the EPA in June 2010 to propose two approaches to regulating the disposal of coal combustion residuals under RCRA. The EPA's long-term objective is to phase out the wet handling of coal ash and the use of surface impoundments (ash ponds) in favor of dry ash handling and disposal in lined

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[7] *Id.* Slide 14.

[8] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 17. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.

[9] US EPA, Office of Air and Radiation. *Reducing Air Pollution from Power Plants*. September 24, 2010. Slide 7. Available at: http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20AIR%20Presentation%20Sept%2024%202010%20_%20Sam%20Napolitano.pdf.

[10] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 19. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.

landfills. Approximately one-third of the coal capacity in the United States uses wet ash handling and storage systems.[11]

The first proposal would regulate coal ash under subtitle C of RCRA and would create a program imposing federally enforceable requirements for waste management and disposal, including the phase-out of wet handling and existing surface impoundments. If EPA pursues the implementation of a coal ash rule under subtitle C, states would be required to adopt the new federal requirements.[12]

The second proposal would regulate coal ash under subtitle D of RCRA, and would apply to coal combustion residuals that are disposed of in landfills or surface impoundments. Under subtitle D, the federal government sets national criteria that are used by the states to issue waste management permits, but states are not required to adopt the federal standards. Utilities would likely continue operating surface impoundments, but states and citizens could seek to enforce new federal requirements through citizen suits in the event of environmental damage.

The Edison Electric Institute (EEI) estimates that the costs to convert bottom ash handling systems to dry ash handling systems are $20 million per unit, while costs to convert fly ash handling systems are $10-$15 million per unit.[13] Costs of new landfills for dry ash are between $30 and $50 million.[14]

A date for release of the final coal combustion residuals rule has yet to be determined. If the subtitle C proposal were adopted, implementation would depend on the timing of the approvals from each of the states, which is expected to take at least two years. A subtitle D rule would become effective six months after promulgation of the rule for most of the provisions, but specific provisions would have a longer effective date.[15]

Clean Water Act § 316(b)

Thermal power plants using water for cooling purposes use one of three types of cooling systems: once-through, recirculating, and dry cooling. Once-through systems withdraw water in large volumes and then discharge it back into the same water body at elevated temperatures. Recirculating systems withdraw water in smaller volumes, and continuously circulate the cooling water through a plant's heat exchangers with the aid of

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[11] Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 66.

[12] US EPA. *Coal Combustion Residuals – Key Differences Between Subtitle C and Subtitle D Options*. Available at: http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccr-rule/ccr-table.htm.

[13] Edison Electric Institute estimates taken from: Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 66.

[14] *Id*.

[15] US EPA. *Coal Combustion Residuals – Key Differences Between Subtitle C and Subtitle D Options*. Available at: http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccr-rule/ccr-table.htm.

cooling towers. Dry cooling systems are closed-loop systems that do not rely on cooling water, but instead on forced draft air flow.

Section 316(b) of the Clean Water Act requires that new power plants use the best available cooling water intake technologies for minimizing adverse environmental impacts.   Adverse environmental impacts include the intake of aquatic organisms with cooling water when using once-through systems.

The EPA promulgated a 316(b) rule in 2004 that covered large existing power plants with water intake in excess of 50 million gallons per day.   In 2007, the Second Circuit Court of Appeals remanded this rule to the EPA. Absent federal regulations, states have begun to consider and adopt rules governing the retrofit of existing power plants with closed-loop cooling systems. On March 10, 2010, New York's Department of Environmental Conservation proposed a policy that would set a closed-cycle cooling performance goal at all of the state's power plants.[16] The California State Water Resources Control Board issued regulations on May 4, 2010 that would require many steam generators to replace once-through systems with closed-loop systems, reducing cooling water intake by 93%.[17] EPA is developing revised national regulatory standards implementing Section 316(b) for existing power plants and manufacturing facilities, and plans to publish a Notice of Proposed Rulemaking in March 2011.   The EPA already has taken comments on an Information Collection Request, and issued proposed rules on March 16, 2011, including specific rules for limiting impingement, which will generally require only advanced screens, and a process for determining best available technology for entrainment for large water users.[18] The entrainment analyses may require some existing plants to retrofit closed-loop systems, such as cooling towers.[19]

Regional Haze Rule

The Clean Air Act defines as a national goal the remedying of existing visibility impairment that results from manmade air pollution in all "Class I" areas (e.g., most

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[16] New York State Department of Environmental Conservation. *CP-nn/Best Technology Available (BTA) for Cooling Water Intake Structures.* March 10, 2010. Available at: http://www.dec.ny.gov/docs/fish_marine_pdf/drbtapolicy1.pdf.

[17] California State Water Resources Control Board. *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*. May 4, 2010. Available at: http://www.swrcb.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/otcpolicy_final050410.pdf.

[18] US EPA. *Fact Sheet: Proposed Information Collection Request for a General Population Survey to Allow the Estimation of Benefits for the Clean Water Act Section 316(b) Cooling Water Intake Structures Rulemaking.* July 2010. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/316factsheet2010.pdf.

[19] There are 651 generating units with water intake above 50 million gallons per day.   Of these 651 generators, there are 404 that are not currently equipped with closed-loop cooling systems.
Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 72.

national parks and wilderness areas). See 42 U.S.C. § 7491(a)(1). EPA's implementing rules require states to create plans to achieve natural visibility conditions by 2064 with enforceable reductions in haze-causing pollution from individual sources and other measures to meet "reasonable further progress" milestones. See generally 40 C.F.R. §51.308-309.

The Clean Air Act's Regional Haze Rule was promulgated in 1999, and revised in 2005. A key component of the haze rule is the imposition of air pollution controls on certain existing facilities that impact visibility in Class I areas. Specifically, the rules require emissions limits on haze-causing pollutants; these limits are represented by "best available retrofit technology" (BART). BART limits are established for air pollutants that impact visibility in our national parks and wilderness areas – namely, SO_2, NO_x, and PM.

Under the Clean Air Act, States have the primary responsibility for developing these requirements, but EPA must determine that a state's plan to achieve natural visibility, including its imposition of BART limits on certain sources, comply with the Clean Air Act's requirements. If EPA finds the plans do not fully meet its regulations, EPA must adopt a federal plan and BART requirements that comply with its regulations. Affected facilities must achieve BART emissions limitations as expeditiously as practicable, but no later than five years from the date EPA approves the state plan or adopts a federal plan.

Exhibit C-1: EPA Regulations Schedule by Year

	2008	2009	2010	2011	2012	2013	2014	2015
Ozone	Revised Ozone NAAQS		Reconsidered Ozone NAAQS	Final EPA Nonattainment Designations			Next Ozone NAAQS Revision	
SO_2/NO_x			NO_x Primary NAAQS SO_2 Primary NAAQS		NO_x/SO_2 Secondary NAAQS			
Clean Air Transport Rule	CAIR Vacated CAIR Remanded	Begin CAIR Phase I Annual NO_x Cap Begin CAIR Phase I Seasonal NO_x Cap	Begin CAIR Phase I Annual SO_2 Cap Proposed CATR Rule	Final CATR Rule Expected	Beginning CATR Phase I Annual SO_2 & NO_x caps Beginning CATR Phase I Seasonal SO_2 & NO_x Caps		Compliance with CATR Rule Beginning CATR Phase II Annual SO_2 & NO_x Caps	
Hg/HAPS Air Toxics Rule	CAMR & Delisting Rule Vacated			HAPS MACT Proposed Rule in March HAPS MACT Final Rule Expected in November				HAPS MACT Compliance Three Years After Final Rule

Exhibit C-1: EPA Regulations Schedule (Continued)

	2008	2009	2010	2011	2012	2013	2014	2015
Water			316(b) Proposed Rule Expected	Effluent Guidelines Proposed Rule	316(b) Final Rule Expected	Effluent Guidelines Final Rule Expected	316(b) Compliance Three to Four Years After Final Rule	Effluent Guidelines Compliance Three to Five Years After Final Rule
PM 2.5	PM-2.5 SIPS due			Next PM-2.5 NAAQS Revision	Next PM-2.5 SIPs due	New PM-2.5 NAAQS Designations		
Coal Ash			Proposed Rule for CCBs Management	Final Rule for CCBs Management		Begin Compliance Requirements Under final CCB Rule (Ground Water Monitoring, Double Monitors, Closure, Dry Ash Conversion)		

Notes

NAAQS	National Ambient Air Quality Standards
NO_x	Nitrogen oxide
SO_2	Sulfur dioxide
$PM_{2.5}$	Particulate matter less than 2.5 microns in diameter
CAIR	Clean Air Interstate Rule
CATR	Clean Air Transport Rule
HAPs	Hazardous Air Pollutants
CAMR	Clean Air Mercury Rule
MACT	Maximum Achievable Control Technology
CCBs	Coal Combustion By-products
SIPs	State Implementation Plans

Exhibit C-2: Renewable Requirements and Qualifying Technologies

	Connecticut[1]			Maine		Massachusetts[2,3]				New Hampshire				Rhode Island		Vermont
	I	II	III	I	II	I	I - Solar[4]	II	II - WTE	I	II	III	IV	New	New or Existing	New
First Compliance Year	2004	2004	2007	2008	2000	2003	2010	2009	2009	2009	2009	2009	2009	2007	2007	2013[5]
Vintage Requirement	See hydro; otherwise none.		post-1/06	post-9/05	none	post-1/98	post-1/08	pre-1/98	pre-1/98	post-1/06	post-1/06	pre-1/06	pre-1/06	post-1/98	pre-1/98	post-1/05
Fuel Type / Technology																
Biomass	NOx limit = 0.075 lbs/MMBtu	NOx limit = 0.2 lbs/MMBtu		< 100 MW	< 100 MW	Advanced Conversion Technology; emissions per DEP		emissions per DEP		NOx limit = 0.075 lbs/MMBtu. PM limit = 0.02 lbs/MMBtu.		<= 25 MW w/ same emissions limits at Class I		High st'd for clean wood fuel.	High st'd for clean wood fuel.	✓
Biomass Thermal										✓						
Fuel Cells	✓	✓		< 100 MW	< 100 MW	✓ if run on RE fuel		✓ if run on RE fuel		✓ if run on RE fuel				✓ if run on RE fuel	✓ if run on RE fuel	✓ if run on RE fuel
Geothermal				< 100 MW	< 100 MW	✓		✓		✓				✓	✓	✓
Hydro	<= 5 MW, ROR, post-1/03	<= 5 MW ROR		< 100 MW	< 100 MW	New + incremental hydro < 25 MW		<= 5 MW		incremental MWh over historic baseline			<= 5 MW	< 30 MW	< 30 MW	<= 200 MW
Methane: includes landfill gas, anerobic digestion, sewage plant wastes	Yes + LFG by NG pipeline from outside ISO-NE also eligible.	Yes + LFG by NG pipeline from outside ISO-NE also eligible.		< 100 MW	< 100 MW	✓		✓		✓		✓		✓	✓	✓
MSW & WTE		✓			✓ w/ recycling			✓	✓							
Ocean Thermal	✓	✓				✓		✓		✓				✓	✓	
Solar Photovoltaic	✓	✓		< 100 MW	< 100 MW	✓	≤ 6 MW per parcel; in MA; BTM	✓		✓	✓			✓	✓	✓
Solar Thermal Electric	✓	✓				✓	≤ 6 MW per parcel; in MA; BTM	✓		✓	✓			✓	✓	✓
Tidal	✓	✓		< 100 MW	< 100 MW	✓		✓		✓				✓	✓	
Wave	✓	✓		< 100 MW	< 100 MW	✓		✓		✓				✓	✓	
Wind	✓	✓		✓	< 100 MW	✓		✓		✓				✓	✓	✓

Exhibit C-2: Renewable Requirements and Qualifying Technologies (Continued)

	Connecticut[1]			Maine		Massachusetts[2,3]				New Hampshire				Rhode Island		Vermont
	I	II	III	I	II	I	I - Solar[4]	II	II - WTE	I	II	III	IV	New	New or Existing	New
First Compliance Year	2004	2004	2007	2008	2000	2003	2010	2009	2009	2009	2009	2009	2009	2007	2007	2013[5]
Vintage Requirement	See hydro; otherwise none.		post-1/06	post-9/05	none	post-1/98	post-1/08	pre-1/98	pre-1/98	post-1/06	post-1/06	pre-1/06	pre-1/06	post-1/98	pre-1/98	post-1/05
Fuel Type / Technology																
Combined Heat & Power			w/ min operating efficiency of 50%		< 100 MW											if run on qualifying RE fuel
Waste Heat or Pressure			✓ post 4/07													
Energy Efficiency																
Conservation & Load Management			✓													
Obligated Entities	Includes investor-owned utilities and competitive LSEs, but excludes municipal and cooperative utilities.									Includes IOUs, Cooperatives and competitive LSEs.				Narragansett Electric & competitive LSEs		All retail LSEs
Geographic Eligibility	Within ISO-NE; or imported from adjacent control areas if the energy is delivered and settleed in the market settlement system.															Within VT[6]
Verification Mechanism	NEPOOL Generation Information System															None
Compliance Period	Annual. January 1 to December 31.															
Alternative Compliance Payment	Penalty Payment is fixed at $55/MWh, all years	Penalty Payment is fixed at $55/MWh, all years	Penalty Payment is fixed at $55/MWh, all years	$62.13/MWh in 2011; adj. annually by CPI.		$62.13/MWh in 2011; adj. annually by CPI.	$550/MWh in 2011; DOER may reduce by up to 10% annually	$25.50/MWh in 2011; adj. annually by CPI.	$10.20Wh in 2011; adj. annually by CPI.	$62.13/MWh in 2011; adj. annually by CPI.	$159.98/MWh in 2009; adj. annually by CPI.	$29.87/MWh in 2009; adj. annually by CPI.	$29.87/MWh in 2009; adj. annually by CPI.	$62.13/MWh in 2011; adj. annually by CPI.	$62.13/MWh in 2011; adj. annually by CPI.	
Banking	Compliance with Class I/New RPS requirements is bankable for 2 years; annual bankable quantity capped at 30% of current year's obligation.															

(1) Revisions to the Connecticut RPS are the subject of discussion in the 2011 Legislature. Reductions to RPS targets and the eligibility of all hydropower for Class 1 have been proposed.

(2) Massachusetts' RPS regulations are currently subject to revisions related to the eligibility of both proposed and existing biomass facilities.

(3) Massachusetts' RPS also includes an Alternate Energy Portfolio Standard (APS), which governs the utilization of certain non-renewable resources, and is therefore not included in this analysis.

(4) Solar projects receiving funding from the MA Clean Energy Center prior to 1/1/2010, or more than 67% of total funding through the American Reinvestment and Recovery Act are not eligible.

Governor's office is compiling a comprehensive energy plan.

(6) Out-of-state projects owned by, or under contract to, Vermont retail providers may also qualify - with PSB approval.

Exhibit C-3: Summary of Annual State RPS Requirements

	Connecticut[1]			Maine		Massachusetts				New Hampshire				Rhode Island		Vermont[2]
Year	I	I or II	III	I	II	I	I - Solar[3,4]	II	II-WTE	I	II	III	IV	New	New or Existing	New
2009	6.00%	3.00%	3.00%	2.00%	30.00%	4.00%	0.00%	3.60%	3.50%	0.50%	0.00%	4.50%	1.00%	2.00%	2.00%	0.00%
2010	7.00%	3.00%	4.00%	3.00%	30.00%	5.00%	0.0679%	3.60%	3.50%	1.00%	0.04%	5.50%	1.00%	2.50%	2.00%	0.00%
2011	8.00%	3.00%	4.00%	4.00%	30.00%	6.00%	per DOER	3.60%	3.50%	2.00%	0.08%	6.50%	1.00%	3.50%	2.00%	0.00%
2012	9.00%	3.00%	4.00%	5.00%	30.00%	7.00%	per DOER	3.60%	3.50%	3.00%	0.15%	6.50%	1.00%	4.50%	2.00%	0.00%
2013	10.00%	3.00%	4.00%	6.00%	30.00%	8.00%	per DOER	3.60%	3.50%	4.00%	0.20%	6.50%	1.00%	5.50%	2.00%	1.00%
2014	11.00%	3.00%	4.00%	7.00%	30.00%	9.00%	per DOER	3.60%	3.50%	5.00%	0.30%	6.50%	1.00%	6.50%	2.00%	2.00%
2015	12.50%	3.00%	4.00%	8.00%	30.00%	10.00%	per DOER	3.60%	3.50%	6.00%	0.30%	6.50%	1.00%	8.00%	2.00%	3.00%
2016	14.00%	3.00%	4.00%	9.00%	30.00%	11.00%	per DOER	3.60%	3.50%	7.00%	0.30%	6.50%	1.00%	9.50%	2.00%	4.00%
2017	15.50%	3.00%	4.00%	10.00%	30.00%	12.00%	per DOER	3.60%	3.50%	8.00%	0.30%	6.50%	1.00%	11.00%	2.00%	5.00%
2018	17.00%	3.00%	4.00%	10.00%	30.00%	13.00%	per DOER	3.60%	3.50%	9.00%	0.30%	6.50%	1.00%	12.50%	2.00%	5.00%
2019	18.50%	3.00%	4.00%	10.00%	30.00%	14.00%	per DOER	3.60%	3.50%	10.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2020	20.00%	3.00%	4.00%	10.00%	30.00%	15.00%	per DOER	3.60%	3.50%	11.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2021	20.00%	3.00%	4.00%	10.00%	30.00%	16.00%	per DOER	3.60%	3.50%	12.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2022	20.00%	3.00%	4.00%	10.00%	30.00%	17.00%	per DOER	3.60%	3.50%	13.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2023	20.00%	3.00%	4.00%	10.00%	30.00%	18.00%	per DOER	3.60%	3.50%	14.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2024	20.00%	3.00%	4.00%	10.00%	30.00%	19.00%	per DOER	3.60%	3.50%	15.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%

(1) Revisions to the Connecticut RPS are the subject of discussion in the 2011 Legislature. Proposals include reducing the RPS target to 11.5% by 2020.

(2) This study assumes the adoption of a new RPS, commencing in 2013, of 5% by 2017 which is incremental to all previously enacted goals and requires REC retirement.

(3) The MA Solar Carve-Out represents a portion of the Class 1 requirement, not an additional requirement. The annual Solar Carve-Out target is calculated each year by MA DOER.

(4) The goal of the Massachusetts Solar Carve-Out is the installation and operation of 400 MW of solar generating capacity.

Exhibit C-4: AESC 2011 Renewable Portfolio Standards, REC Price Forecast, and Avoided RPS Costs by State (2011$)

AESC 2011: Renewable Portfolio Standard (RPS) Targets, Renewable Energy Credit (REC) Price Forecasts, and Avoided RPS Costs in $/MWh of Load

(all values in 2011 dollars)

			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CONNECTICUT	RPS Targets (%)	Class 1	8.0%	9.0%	10.0%	11.0%	12.5%	14.0%	15.5%	17.0%	18.5%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
		Class 2	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
		Class 3	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
	REC Prices ($/MWh)	Class 1	13.48	14.60	15.23	16.04	16.76	17.29	17.08	10.99	5.14	6.63	3.46	6.84	9.82	10.23	7.85	4.12
		Class 2	0.91	0.89	0.87	0.86	0.84	0.82	0.81	0.79	0.78	0.76	0.75	0.73	0.72	0.70	0.69	0.68
		Class 3	10.00	9.80	9.61	9.42	9.24	9.06	8.88	8.71	8.53	8.37	8.20	8.04	7.88	7.73	7.58	7.43
	Loss Adjustment		8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost: $/MWh of Load	Class 1	$1.16	$1.42	$1.64	$1.91	$2.26	$2.61	$2.86	$2.02	$1.03	$1.43	$0.75	$1.48	$2.12	$2.21	$1.70	$0.89
		Class 2	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
		Class 3	$0.43	$0.42	$0.42	$0.41	$0.40	$0.39	$0.38	$0.38	$0.37	$0.36	$0.35	$0.35	$0.34	$0.33	$0.33	$0.32
MAINE	RPS Targets (%)	Class 1	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
		Class 2	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
	REC Prices ($/MWh)	Class 1	9.00	11.64	11.68	12.30	12.85	13.26	13.10	9.04	5.14	6.63	3.46	6.84	9.82	10.23	7.85	4.12
		Class 2	0.18	0.18	0.17	0.17	0.17	0.16	0.16	0.16	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.13
	Loss Adjustment		8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost: $/MWh of Load	Class 1	$0.39	$0.63	$0.76	$0.93	$1.11	$1.29	$1.41	$0.98	$0.55	$0.72	$0.37	$0.74	$1.06	$1.11	$0.85	$0.44
		Class 2	$0.06	$0.06	$0.06	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.04	$0.04

Exhibit C-4: AESC 2011 Renewable Portfolio Standards, REC Price Forecast, and Avoided RPS Costs by State (2011$) (Continued)

AESC 2011: Renewable Portfolio Standard (RPS) Targets, Renewable Energy Credit (REC) Price Forecasts, and Avoided RPS Costs in $/MWh of Load

(all values in 2011 dollars)

			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MASSACHUSETTS	RPS Targets (%)	Class 1	5.84%	6.78%	7.73%	8.65%	9.54%	10.41%	11.24%	12.10%	13.10%	14.10%	15.10%	16.10%	17.16%	18.33%	19.56%	20.83%
		Solar Carve-Out	0.1627%	0.22%	0.27%	0.35%	0.46%	0.59%	0.76%	0.90%	0.90%	0.90%	0.90%	0.90%	0.84%	0.67%	0.44%	0.17%
		Class 2	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
		Class 2-WTE	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
		APS	2.00%	2.50%	3.00%	3.50%	3.75%	4.00%	4.25%	4.50%	4.75%	5.00%	5.25%	5.50%	5.75%	6.00%	6.25%	6.50%
	REC Prices ($/MWh)	Class 1	$ 14.95	$ 17.05	$ 22.44	$ 23.63	$ 24.69	$ 25.48	$ 25.17	$ 14.96	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Solar Carve-Out	$ 525.00	$ 435.42	$ 381.68	$ 355.49	$ 331.09	$ 308.37	$ 287.21	$ 267.50	$ 249.14	$ 232.04	$ 222.87	$ 207.57	$ 199.19	$ 190.97	$ 182.95	$ 175.13
		Class 2	$ 22.88	$ 20.52	$ 18.24	$ 16.04	$ 16.76	$ 17.29	$ 17.08	$ 10.99	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Class 2-WTE	$ 5.27	$ 5.17	$ 5.07	$ 4.97	$ 4.87	$ 4.77	$ 4.68	$ 4.59	$ 4.50	$ 4.41	$ 4.32	$ 4.24	$ 4.16	$ 4.07	$ 3.99	$ 3.92
		APS	$ 19.00	$ 18.79	$ 18.57	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost: $/MWh of Load	Class 1	$0.94	$1.25	$1.87	$2.21	$2.54	$2.86	$3.05	$1.95	$0.73	$1.01	$0.56	$1.19	$1.82	$2.03	$1.66	$0.93
		Solar Carve-Out	$0.92	$1.05	$1.12	$1.35	$1.64	$1.97	$2.36	$2.61	$2.43	$2.26	$2.17	$2.03	$1.80	$1.38	$0.88	$0.33
		Class 2	$0.89	$0.80	$0.71	$0.62	$0.65	$0.67	$0.66	$0.43	$0.20	$0.26	$0.13	$0.27	$0.38	$0.40	$0.31	$0.16
		Class 2-WTE	$0.20	$0.20	$0.19	$0.19	$0.18	$0.18	$0.18	$0.17	$0.17	$0.17	$0.16	$0.16	$0.16	$0.15	$0.15	$0.15
		APS	$0.41	$0.51	$0.60	$0.69	$0.74	$0.79	$0.84	$0.89	$0.94	$0.99	$1.04	$1.09	$1.14	$1.19	$1.24	$1.29
NEW HAMPSHIRE	RPS Targets (%)	Class 1	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%	16.0%	16.0%
		Class 2	0.08%	0.15%	0.20%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
		Class 3	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
		Class 4	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
	REC Prices ($/MWh)	Class 1	$ 15.71	$ 17.41	$ 26.21	$ 27.60	$ 28.84	$ 29.76	$ 29.39	$ 17.03	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Class 2	$ 25.00	$ 18.75	$ 24.13	$ 24.81	$ 25.93	$ 26.76	$ 26.42	$ 15.70	$ 5.39	$ 6.96	$ 3.63	$ 7.18	$ 10.32	$ 10.75	$ 8.24	$ 4.32
		Class 3	$ 18.75	$ 17.82	$ 16.91	$ 16.04	$ 16.76	$ 17.29	$ 17.08	$ 10.99	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Class 4	$ 24.47	$ 21.56	$ 18.74	$ 16.04	$ 16.76	$ 17.29	$ 17.08	$ 10.99	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost: $/MWh of Load	Class 1	$0.34	$0.56	$1.13	$1.49	$1.87	$2.25	$2.54	$1.65	$0.55	$0.79	$0.45	$0.96	$1.49	$1.66	$1.36	$0.71
		Class 2	$0.02	$0.03	$0.05	$0.08	$0.08	$0.09	$0.09	$0.05	$0.02	$0.02	$0.01	$0.02	$0.03	$0.03	$0.03	$0.01
		Class 3	$1.32	$1.25	$1.19	$1.13	$1.18	$1.21	$1.20	$0.77	$0.36	$0.47	$0.24	$0.48	$0.69	$0.72	$0.55	$0.29
		Class 4	$0.26	$0.23	$0.20	$0.17	$0.18	$0.19	$0.18	$0.12	$0.06	$0.07	$0.04	$0.07	$0.11	$0.11	$0.08	$0.04

Exhibit C-4: AESC 2011 Renewable Portfolio Standards, REC Price Forecast, and Avoided RPS Costs by State (2011$) (Continued)

AESC 2011: Renewable Portfolio Standard (RPS) Targets, Renewable Energy Credit (REC) Price Forecasts, and Avoided RPS Costs in $/MWh of Load

(all values in 2011 dollars)

State			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RHODE ISLAND	RPS Targets (%)	New	3.5%	4.5%	5.5%	6.5%	8.0%	9.5%	11.0%	12.5%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%
		Existing	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	REC Prices ($/MWh)	New	$ 15.28	$ 17.41	$ 20.83	$ 21.93	$ 22.92	$ 23.65	$ 23.35	$ 14.07	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Existing	$ 0.76	$ 0.75	$ 0.73	$ 0.72	$ 0.70	$ 0.69	$ 0.67	$ 0.66	$ 0.65	$ 0.64	$ 0.62	$ 0.61	$ 0.60	$ 0.59	$ 0.58	$ 0.56
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost:	**New**	**$0.58**	**$0.85**	**$1.24**	**$1.54**	**$1.98**	**$2.43**	**$2.77**	**$1.90**	**$0.78**	**$1.00**	**$0.52**	**$1.03**	**$1.49**	**$1.55**	**$1.19**	**$0.62**
	$/MWh of Load	**Existing**	**$0.02**	**$0.02**	**$0.02**	**$0.02**	**$0.02**	**$0.01**	**$0.01**	**$0.01**	**$0.01**	**$0.01**	**$0.01**	**$0.01**	**$0.01**	**$0.01**	**$0.01**	**$0.01**
VERMONT	RPS Targets (%)	New	0%	0%	1%	2%	3%	4%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	REC Prices ($/MWh)	New	$ -	$ -	$ 20.83	$ 21.93	$ 22.92	$ 23.65	$ 23.35	$ 14.07	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost:	**New**	**$0.00**	**$0.00**	**$0.22**	**$0.47**	**$0.74**	**$1.02**	**$1.26**	**$0.76**	**$0.28**	**$0.36**	**$0.19**	**$0.37**	**$0.53**	**$0.55**	**$0.42**	**$0.22**

Exhibit C-4: AESC 2011 Renewable Portfolio Standards, REC Price Forecast, and Avoided RPS Costs by State (2011$) (Continued)

Assumptions:

1 RPS Targets for CT, ME, MA, NH & RI are based on state-specific legislation and regulation in effect as of April 15, 2011

2 Vermont currently has a non-binding goal of 20 percnet by 2017. VT's minimum obligation is to meet incremental load growth from 2005 - 2012 with qualifying resources. A minimum goal of generating 5 percent of VT's 2005 sales is also included in the current law. No F is required. This AESC 2011 study assumes adoption of an RPS, commencing in 2013, of 5 percent by 2017 which is incremental to all goals previously described and requires REC retirement.

3 For Class I requirements, 2011 & 2012 REC prices are based on historic average broker quotes from January to April 2011. For Class II requirements, 2011 REC prices are based on a 12-month (May 2010 to April 2011) historic average of broker quotes and/or bid-ask spread

4 Prices for MA Class I, CT Class I, NH Class I, ME Class I, and RI "New" are assumed to reflect the new renewables cost of entry beginning in 2019. Prices are interpolated between 2013 and 2018.

5 The incremental VT RPS requirement (described in Note 2) is assumed to have eligibility criteria similar enough to RI Class 1 that VT REC prices will approximately the levels expected in this market.

6 The MA Solar Carve Out (a sub-set of MA Class I) is assumed to reach its 400 MW target in 2018. The target is assumed to remain at this level through 2022. This is the proxy date for the point at which the last remaining "Opt-In Term" is expected to expire. Beginning in Carve-Out is assumed to begin to sunset into MA Class I at the same rate as it ramped up, reaching zero carve-out shortly after the study period ends. Reductions in the installed cost of new solar facilities are asumed to drive SREC prices toward the $300 auction floor pr to 2018, with steeper declines in the early years. Beginning in 2019 (one year after the 400 MW target is reached) supply and demand dynamics may cause the market price of SRECs to drop below the auction floor price of $300, notwithstanding the fact that some SRECs for the auction. MA DOER's SREC market structure is yet untested, and it is not clear whether an auction floor price will be able to be maintained once there is a substantial amount of supply in the market.

7 CT Class II, MA Class II-WTE, ME Class II, and RI "Existing" REC markets are in surplus. Therefore, REC prices in these markets are expected to remain relatively constant.

8 The MA Class II market has overlapping eligibility with CT Class I. In addition, while there is theoretically ample supply to meet MA Class II, fewer generators than expected have undertaken the steps necessary to comply with the eligibility criteria and become certified. T MA Class II market is currently in shortage. In the long-run, MA Class II REC prices are assumed to be the lesser of CT Class I and 90 percent of the MA Class II Alternative Compliance Payment (ACP) rate.

9 REC prices for MA APS are forecasted at 90 percent of the Alternative Compliance Payment (ACP) rate.

10 The CT Class III market has an administratively-set REC price floor of $10 per MWh. Based on the performance of this market to date, CT Class 3 compliance prices are expected to remain at $10 per MWh throughout the study period.

11 Existing solar facilities across New England are eligible for NH Class II. As such, this market is expected to remain in balance, trend toward the MA Class I REC price between 2011 and 2014, and settle marginally above the MA Class I REC price for the remainder of the stud

12 The NH Class III and NH CLass IV markets have overlapping eligibility with CT Class I. In the long-run, therefore, NH-III and NH-IV REC prices are assumed to be the lesser of CT Class I and 90 percent of their respective Alternative Compliance Payment (ACP) rates.

Exhibit C-5: Market Analytics Locational Prices by Zone

Zone: Maine

Year	Winter			Summer		
	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	47.11	41.77	44.3	48.96	38.00	43.2
2012	48.78	42.84	45.7	53.19	41.07	46.8
2013	49.59	43.73	46.5	52.26	41.99	46.9
2014	49.81	44.27	46.9	53.18	42.59	47.6
2015	54.30	47.63	50.8	57.21	46.35	51.5
2016	54.40	47.17	50.6	59.57	46.59	52.8
2017	54.79	47.98	51.2	58.59	46.37	52.2
2018	60.43	54.17	57.2	65.22	52.33	58.5
2019	61.39	56.11	58.6	66.40	53.70	59.7
2020	63.10	55.49	59.1	68.02	54.68	61.0
2021	64.89	58.07	61.3	70.35	56.27	63.0
2022	66.86	58.97	62.7	71.93	58.82	65.1
2023	71.19	62.10	66.4	76.41	61.44	68.6
2024	74.04	64.28	68.9	77.79	63.56	70.3
2025	74.74	65.19	69.7	79.05	64.80	71.6
2026	75.92	65.86	70.7	79.09	64.96	71.7

Zone: Vermont

Year	Winter			Summer		
	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	50.10	42.29	46.0	55.88	40.24	47.7
2012	51.65	43.50	47.4	61.41	43.41	52.0
2013	52.90	45.57	49.1	63.19	44.96	53.6
2014	54.33	46.83	50.4	65.54	45.70	55.1
2015	59.48	50.92	55.0	70.28	49.86	59.6
2016	59.75	50.86	55.1	76.15	50.36	62.6
2017	60.08	51.99	55.8	75.74	49.84	62.2
2018	66.18	58.43	62.1	85.33	56.69	70.3
2019	67.02	60.12	63.4	83.93	57.83	70.3
2020	68.92	59.85	64.2	80.24	58.76	69.0
2021	70.57	62.12	66.1	81.81	60.48	70.6
2022	72.53	63.84	68.0	83.37	62.46	72.4
2023	76.59	66.67	71.4	87.32	65.66	76.0
2024	79.30	68.49	73.6	88.68	67.33	77.5
2025	80.34	69.35	74.6	89.89	69.35	79.1
2026	82.23	71.10	76.4	93.75	70.21	81.4

Zone: New Hampshire

Year	Winter			Summer		
	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	48.81	41.89	45.2	52.70	39.42	45.7
2012	50.47	42.97	46.5	57.13	42.47	49.5
2013	51.37	44.62	47.8	56.38	43.86	49.8
2014	52.74	45.98	49.2	57.39	44.63	50.7
2015	57.78	49.94	53.7	61.72	48.45	54.8
2016	58.03	49.72	53.7	64.26	48.93	56.2
2017	58.40	51.00	54.5	63.19	48.54	55.5
2018	64.39	57.47	60.8	70.47	55.28	62.5
2019	65.36	59.19	62.1	71.55	56.60	63.7
2020	66.97	58.57	62.6	72.94	57.40	64.8
2021	68.81	61.06	64.8	75.55	59.15	67.0
2022	70.60	62.52	66.4	77.05	61.23	68.8
2023	74.73	65.39	69.8	81.88	64.36	72.7
2024	77.58	67.34	72.2	82.96	66.02	74.1
2025	78.60	68.21	73.2	84.15	68.15	75.8
2026	79.99	69.12	74.3	84.00	68.27	75.8

Zone: Connecticut

Year	Winter			Summer		
	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	50.80	42.61	46.5	57.36	40.70	48.6
2012	52.35	43.99	48.0	62.71	43.95	52.9
2013	53.31	45.65	49.3	64.72	44.99	54.4
2014	54.86	47.18	50.8	66.36	46.07	55.7
2015	60.08	51.32	55.5	71.07	50.41	60.2
2016	60.35	51.31	55.6	77.12	50.91	63.4
2017	60.64	52.44	56.3	76.59	50.34	62.8
2018	66.80	58.92	62.7	86.28	57.00	70.9
2019	67.68	60.60	64.0	84.85	58.38	71.0
2020	69.67	60.45	64.8	81.22	59.32	69.8
2021	71.26	62.71	66.8	82.74	61.03	71.4
2022	73.25	64.47	68.6	84.35	63.02	73.2
2023	77.42	67.34	72.1	88.35	66.29	76.8
2024	80.14	69.19	74.4	90.17	67.98	78.5
2025	81.19	70.10	75.4	91.14	70.04	80.1
2026	83.28	71.98	77.4	95.24	71.00	82.5

Exhibit C-5: Market Analytics Locational Prices by Zone (Continued)

Zone	Massachusetts					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	49.64	42.25	45.8	55.65	39.92	47.4
2012	51.33	43.34	47.1	61.31	43.07	51.8
2013	52.45	45.31	48.7	62.96	44.51	53.3
2014	53.83	46.74	50.1	65.23	45.48	54.9
2015	59.15	51.04	54.9	70.09	49.72	59.4
2016	59.58	51.03	55.1	76.24	50.25	62.6
2017	59.89	52.20	55.9	75.98	49.77	62.2
2018	65.89	58.52	62.0	85.64	56.51	70.4
2019	66.99	60.46	63.6	84.38	57.68	70.4
2020	68.26	59.46	63.6	79.72	58.34	68.5
2021	70.10	61.84	65.8	81.43	60.20	70.3
2022	71.92	63.34	67.4	82.92	62.00	72.0
2023	76.02	66.06	70.8	86.64	65.06	75.3
2024	78.82	68.01	73.2	88.25	66.87	77.0
2025	80.30	69.18	74.5	89.95	69.11	79.0
2026	81.96	70.82	76.1	93.90	70.11	81.4

Zone	Rhode Island					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	48.50	41.86	45.0	53.72	39.31	46.2
2012	50.16	43.04	46.4	59.58	42.42	50.6
2013	51.31	44.85	47.9	61.15	43.71	52.0
2014	52.71	46.30	49.4	64.04	44.83	54.0
2015	58.13	50.63	54.2	68.43	48.99	58.2
2016	58.39	50.52	54.3	74.43	49.60	61.4
2017	58.54	51.62	54.9	73.91	49.11	60.9
2018	58.52	51.28	54.7	75.90	49.65	62.1
2019	58.29	51.61	54.8	73.98	49.55	61.2
2020	58.38	48.79	53.4	67.30	49.19	57.8
2021	58.99	49.60	54.1	67.51	49.83	58.2
2022	59.25	49.24	54.0	66.59	49.85	57.8
2023	61.79	50.69	56.0	68.63	51.45	59.6
2024	63.23	50.63	56.6	69.66	52.34	60.6
2025	63.43	50.01	56.4	69.59	52.72	60.8
2026	64.09	50.54	57.0	72.16	53.17	62.2

Zone	CT Norwalk/Stamford					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	51.33	43.05	47.0	57.96	41.12	49.1
2012	52.90	44.46	48.5	63.37	44.41	53.4
2013	53.87	46.13	49.8	65.40	45.46	55.0
2014	55.44	47.66	51.4	67.06	46.55	56.3
2015	60.71	51.85	56.1	71.82	50.94	60.9
2016	60.98	51.84	56.2	77.93	51.45	64.1
2017	61.28	52.99	56.9	77.39	50.87	63.5
2018	67.51	59.53	63.3	87.19	57.60	71.7
2019	68.39	61.24	64.6	85.74	58.99	71.7
2020	70.40	61.08	65.5	82.08	59.95	70.5
2021	72.01	63.37	67.5	83.62	61.67	72.1
2022	74.02	65.15	69.4	85.24	63.68	73.9
2023	78.23	68.04	72.9	89.28	66.99	77.6
2024	80.99	69.92	75.2	91.12	68.69	79.4
2025	82.05	70.83	76.2	92.10	70.78	80.9
2026	84.15	72.74	78.2	96.25	71.75	83.4

Zone	CT Southwest Including Norwalk/Stamford					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	51.30	43.02	47.0	57.92	41.10	49.1
2012	52.87	44.43	48.4	63.33	44.38	53.4
2013	53.83	46.10	49.8	65.36	45.43	54.9
2014	55.41	47.63	51.3	67.01	46.52	56.3
2015	60.67	51.82	56.0	71.77	50.90	60.8
2016	60.94	51.81	56.2	77.88	51.42	64.0
2017	61.24	52.96	56.9	77.34	50.84	63.5
2018	67.47	59.49	63.3	87.13	57.56	71.6
2019	68.35	61.20	64.6	85.69	58.95	71.7
2020	70.35	61.04	65.5	82.03	59.91	70.4
2021	71.96	63.33	67.4	83.56	61.63	72.1
2022	73.97	65.11	69.3	85.19	63.64	73.9
2023	78.18	68.00	72.8	89.22	66.94	77.6
2024	80.93	69.87	75.1	91.06	68.65	79.3
2025	81.99	70.79	76.1	92.04	70.73	80.9
2026	84.10	72.69	78.1	96.19	71.71	83.4

Exhibit C-5: Market Analytics Locational Prices by Zone (Continued)

Zone	CT Southwest Excluding Norwalk/Stamford					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	51.28	43.01	46.9	57.90	41.09	49.1
2012	52.85	44.41	48.4	63.31	44.37	53.4
2013	53.82	46.08	49.8	65.34	45.41	54.9
2014	55.39	47.61	51.3	66.99	46.50	56.3
2015	60.65	51.80	56.0	71.74	50.89	60.8
2016	60.92	51.79	56.1	77.85	51.40	64.0
2017	61.21	52.94	56.9	77.32	50.82	63.4
2018	67.44	59.47	63.3	87.10	57.54	71.6
2019	68.33	61.18	64.6	85.66	58.93	71.7
2020	70.33	61.02	65.5	82.00	59.89	70.4
2021	71.94	63.31	67.4	83.53	61.61	72.0
2022	73.94	65.08	69.3	85.16	63.61	73.9
2023	78.16	67.98	72.8	89.19	66.92	77.5
2024	80.91	69.85	75.1	91.03	68.62	79.3
2025	81.96	70.76	76.1	92.01	70.71	80.9
2026	84.07	72.67	78.1	96.15	71.68	83.3

Zone	CT Rest of State					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	50.27	42.18	46.0	56.77	40.28	48.1
2012	51.81	43.54	47.5	62.07	43.50	52.3
2013	52.76	45.18	48.8	64.05	44.53	53.8
2014	54.30	46.71	50.3	65.68	45.60	55.2
2015	59.46	50.80	54.9	70.34	49.89	59.6
2016	59.73	50.78	55.0	76.33	50.39	62.7
2017	60.01	51.90	55.8	75.80	49.82	62.2
2018	66.12	58.33	62.0	85.39	56.42	70.2
2019	66.99	59.99	63.3	83.98	57.78	70.3
2020	68.95	59.82	64.2	80.39	58.72	69.0
2021	70.53	62.06	66.1	81.90	60.40	70.6
2022	72.49	63.81	67.9	83.48	62.37	72.4
2023	76.62	66.65	71.4	87.44	65.61	76.0
2024	79.32	68.48	73.6	89.24	67.28	77.7
2025	80.36	69.38	74.6	90.21	69.32	79.3
2026	82.42	71.25	76.6	94.27	70.27	81.7

Zone	SEMA					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	48.92	42.10	45.3	54.72	39.51	46.8
2012	50.64	43.07	46.7	60.37	42.67	51.1
2013	51.70	45.10	48.2	61.90	44.03	52.5
2014	53.04	46.58	49.7	64.08	45.13	54.2
2015	58.44	51.00	54.5	68.81	49.38	58.6
2016	58.81	50.89	54.7	74.92	49.87	61.8
2017	59.09	52.11	55.4	74.72	49.40	61.5
2018	64.94	58.33	61.5	84.22	56.09	69.5
2019	66.20	60.42	63.2	83.12	57.23	69.6
2020	67.58	59.36	63.3	78.60	58.25	67.9
2021	69.68	61.99	65.6	80.69	60.21	70.0
2022	71.17	63.11	66.9	82.07	61.75	71.4
2023	75.72	65.93	70.6	85.78	64.93	74.9
2024	78.20	67.87	72.8	87.45	66.85	76.7
2025	80.43	69.38	74.6	89.46	69.29	78.9
2026	81.52	70.98	76.0	93.46	70.41	81.4

Zone	WCMA					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	50.16	42.33	46.1	55.97	40.33	47.8
2012	51.69	43.56	47.4	61.52	43.51	52.1
2013	52.84	45.53	49.0	63.19	44.94	53.6
2014	54.29	46.78	50.4	65.56	45.69	55.2
2015	59.46	50.88	55.0	70.34	49.90	59.6
2016	59.73	50.85	55.1	76.20	50.41	62.7
2017	60.03	51.96	55.8	75.78	49.87	62.2
2018	66.11	58.38	62.1	85.36	56.68	70.3
2019	66.97	60.08	63.4	83.97	57.83	70.3
2020	68.88	59.83	64.1	80.24	58.73	69.0
2021	70.51	62.07	66.1	81.81	60.43	70.6
2022	72.46	63.81	67.9	83.37	62.41	72.4
2023	76.54	66.66	71.4	87.32	65.62	76.0
2024	79.22	68.48	73.6	88.67	67.28	77.5
2025	80.26	69.38	74.6	89.86	69.32	79.1
2026	82.24	71.22	76.5	93.80	70.27	81.5

Exhibit C-5: Market Analytics Locational Prices by Zone (Continued)

Zone	NEMA					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	49.48	41.94	45.5	55.23	39.58	47.0
2012	51.15	43.03	46.9	60.84	42.71	51.3
2013	52.17	44.87	48.3	62.43	44.09	52.8
2014	53.54	46.27	49.7	64.68	44.95	54.3
2015	58.71	50.47	54.4	69.53	49.12	58.8
2016	59.14	50.44	54.6	75.64	49.63	62.0
2017	59.41	51.57	55.3	75.39	49.15	61.6
2018	65.34	57.84	61.4	85.00	55.80	69.7
2019	66.42	59.73	62.9	83.72	56.97	69.7
2020	67.59	58.55	62.9	78.89	57.41	67.6
2021	69.28	60.87	64.9	80.44	59.24	69.3
2022	71.16	62.41	66.6	81.92	61.05	71.0
2023	74.98	64.96	69.7	85.49	63.96	74.2
2024	77.87	66.94	72.1	87.13	65.75	75.9
2025	79.14	68.04	73.3	88.84	67.93	77.9
2026	80.89	69.60	75.0	92.69	68.88	80.2

Zone	Rest of MA					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	49.66	42.30	45.8	55.72	39.97	47.5
2012	51.36	43.39	47.2	61.38	43.13	51.8
2013	52.49	45.38	48.8	63.04	44.57	53.4
2014	53.88	46.82	50.2	65.32	45.56	55.0
2015	59.22	51.13	55.0	70.18	49.81	59.5
2016	59.65	51.12	55.2	76.34	50.35	62.7
2017	59.96	52.29	55.9	76.07	49.87	62.3
2018	65.98	58.63	62.1	85.74	56.63	70.5
2019	67.09	60.58	63.7	84.48	57.79	70.5
2020	68.37	59.60	63.8	79.85	58.48	68.7
2021	70.23	61.99	65.9	81.58	60.36	70.5
2022	72.04	63.49	67.6	83.08	62.15	72.1
2023	76.18	66.23	71.0	86.83	65.23	75.5
2024	78.97	68.18	73.3	88.42	67.05	77.2
2025	80.49	69.36	74.7	90.13	69.29	79.2
2026	82.13	71.01	76.3	94.09	70.30	81.6

Exhibit C-6: AESC 2011 Reference Case: Avoided Externality Costs

	AESC Long-term Cost	**AESC Allowance Price**		Winter On Peak	Winter Off-Peak	Summer On Peak Energy	Summer Off-Peak
	$/ton (2011$)	$/ton (2011$)	$/ton externality	$/kWh externality			
	a	b	c=a-b	d=c* winter on peak emission rate	e=c* winter off peak emission rate	f=c* summer on peak emission rate	g=c* summer off emission rate
2011	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2012	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2013	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2014	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2015	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2016	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2017	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2018	***$80.00***	***$15.30***	***$64.70***	0.035	0.036	0.034	0.037
2019	***$80.00***	***$18.28***	***$61.73***	0.034	0.034	0.033	0.035
2020	***$80.00***	***$21.25***	***$58.75***	0.032	0.033	0.031	0.034
2021	***$80.00***	***$24.23***	***$55.78***	0.030	0.031	0.030	0.032
2022	***$80.00***	***$27.20***	***$52.80***	0.029	0.029	0.028	0.030
2023	***$80.00***	***$30.18***	***$49.83***	0.027	0.028	0.026	0.029
2024	***$80.00***	***$33.15***	***$46.85***	0.025	0.026	0.025	0.027
2025	***$80.00***	***$36.13***	***$43.88***	0.024	0.024	0.023	0.025
2026	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2027	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2028	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2029	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2030	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2031	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2032	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2033	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2034	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2035	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2036	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2037	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2038	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2039	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2040	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
2041	***$80.00***	***$39.10***	***$40.90***	0.022	0.023	0.022	0.023
			Emission Values (tons/MWh)	0.544	0.554	0.530	0.572

Data taken from long term carbon abatement costs and emission rates from Chapter 6 and from Exhibit 2-4

Exhibit C-7: AESC 2011 RGGI Only Case: Avoided Externality Costs

	AESC Long-term Cost	AESC Allowance Price		Winter On Peak	Winter Off-Peak	Summer On Peak Energy	Summer Off-Peak
	$/ton (2011$)	$/ton (2011$)	$/ton externality	$/kWh externality			
	a	b	c=a-b	d=c* winter on peak emission rate	e=c* winter off peak emission rate	f=c* summer on peak emission rate	g=c* summer off emission rate
2011	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2012	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2013	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2014	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2015	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2016	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2017	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2018	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2019	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2020	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2021	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2022	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2023	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2024	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2025	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2026	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2027	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2028	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2029	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2030	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2031	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2032	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2033	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2034	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2035	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2036	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2037	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2038	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2039	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2040	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2041	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
			Emission Values (tons/MWh)	0.544	0.554	0.530	0.572

Data taken from long term carbon abatement costs and emission rates from Chapter 6 and from Exhibit 2-4

Exhibit C-8: DRIPE Research Bibliography

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Exhibit C-9: Social Discount Rate Summary Table

Table: Summary of Real Discount Rates from Selected Jurisdictions

Jurisdiction	Real Discount Rate	Citation	Rationale
Connecticut	4.68%	Connecticut Natural Gas Commercial and Industrial Energy-Efficiency Potential Study, Final Report, May 7, 2009. Rate converted from nominal rate of 7.09% to real rate using given inflation rate of 2.3%. http://www.ctsavesenergy.org/files/ CTNGPotential090508FINAL.pdf	None Given
Maine	Based on US Treasuries	"The discount rate used for present value calculations shall be the current yield of long-term (10 years or longer) U.S. Treasury securities, adjusted for inflation." Main PUC 65-407, Chapter 380: Electric Energy Conservation Programs. http://www.efficiencymaine.com/docs/AgencyRules/Chapter%20380.pdf	None given
Massachusetts	Based on US Treasuries	"The discount rate used for the Total Resource Cost test should be equal to the historic twelve-month average of the yields of ten-year United States Treasury notes." Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities, D.P.U. 08-50-A, March 16, 2009	None given
New Hampshire	5.0%	Additional Opportunities for Energy Efficiency in New Hampshire, Final Report, January 2009. http://www.puc.state.nh.us/Electric/GDS%20Report/NH%20Additional%20EE%20Opportunities%20Study%202-19-09%20-%20Final.pdf	None given
Rhode Island	7.0%	Rhode Island Energy Efficiency and Resources Management Council (EERMC): Opportunity Report – Phase I, July 15, 2008 http://www.rieermc.ri.gov/documents/OER-EERMC-OpportunityRept(7-15-08).pdf	"The discount rate of seven percent is the federally accepted rate used for a CBA and also takes into account the inflation rate (NOAA)"
Vermont	5.7%	Efficiency Vermont Annual Plan 2011, November 1, 2010. http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_plans/EVT_AnnualPlan2011.pdf	None given
California	8.15%	Following E3's development of an avoided cost calculation methodology in R.04-04-025, E3 developed the "E3 Calculator," used by all California investor-owned utilities to compute the cost-effectiveness of energy efficiency programs. The calculator is updated periodically (last update 8/13/2010) and is available at: http://www.ethree.com/public_projects/cpuc4.html	
New York	5.5%	New York's System Benefits Charge Programs Evaluation and Status Report, May 2010, http://www.nyserda.org/publications/ first_quarter_report_sbc_rev.pdf	None given
Oregon	5.2%	Energy Trust of Oregon. "4.06.000-P: Cost Effectiveness Policy and General Methodology for Energy Trust of Oregon." February 13, 2008. Available at: http://energytrust.org/library/policies/4.06.000.pdf	None given
Washington (1)	Based on utility WACC	*Washington Administrative Code. Chapter 194-37 WAC: Energy Independence. Last updated March 18, 2008. Available at: http://apps.leg.wa.gov/wac/default.aspx?cite=194-37&full=true*	

(1) The Northwest Power and Conservation Council (NWPCC) used a 5% real discount rate in its Sixth Annual "Northwest Power Plan," released February 2010. Utility conservation targets are based on resource potential identified by the NWPCC.

Appendix D: Avoided Natural Gas Cost Results

Table of Exhibits

Exhibit D-1: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Northern Central New England Assuming Some Avoidable Retail Margin (2011$/MMBtu)

Year	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water annual	Heating	All	Non Heating annual	Heating	All	
2011	5.82	5.82	7.35	7.11	5.95	7.18	6.80	6.95
2012	6.34	6.34	7.80	7.58	6.46	7.64	7.28	7.43
2013	6.54	6.54	8.01	7.79	6.67	7.85	7.49	7.64
2014	6.82	6.82	8.39	8.14	6.95	8.23	7.84	7.99
2015	7.39	7.39	8.86	8.63	7.51	8.69	8.33	8.48
2016	7.42	7.42	8.88	8.66	7.55	8.71	8.36	8.51
2017	7.40	7.40	8.87	8.64	7.52	8.70	8.34	8.49
2018	7.42	7.42	8.89	8.67	7.55	8.73	8.37	8.52
2019	7.47	7.47	8.95	8.72	7.59	8.78	8.42	8.57
2020	7.56	7.56	9.04	8.82	7.68	8.88	8.51	8.66
2021	7.66	7.66	9.15	8.92	7.78	8.98	8.62	8.77
2022	7.79	7.79	9.32	9.08	7.91	9.15	8.78	8.93
2023	8.07	8.07	9.59	9.35	8.19	9.42	9.05	9.20
2024	8.26	8.26	9.76	9.53	8.38	9.59	9.22	9.37
2025	8.33	8.33	9.84	9.61	8.46	9.68	9.31	9.46
2026	8.45	8.45	9.98	9.74	8.58	9.81	9.44	9.59
2027	8.58	8.58	10.11	9.87	8.70	9.94	9.57	9.72
2028	8.71	8.71	10.25	10.00	8.83	10.08	9.70	9.85
2029	8.84	8.84	10.38	10.13	8.96	10.21	9.83	9.98
2030	8.97	8.97	10.52	10.27	9.09	10.35	9.97	10.12
2031	9.10	9.10	10.66	10.41	9.23	10.49	10.11	10.26
2032	9.24	9.24	10.80	10.55	9.36	10.63	10.25	10.40
2033	9.38	9.38	10.94	10.69	9.50	10.78	10.39	10.54
2034	9.52	9.52	11.09	10.83	9.64	10.92	10.53	10.68
2035	9.66	9.66	11.23	10.97	9.78	11.07	10.68	10.82
2036	9.80	9.80	11.38	11.12	9.92	11.22	10.83	10.97
2037	9.95	9.95	11.53	11.27	10.07	11.37	10.97	11.12
2038	10.10	10.10	11.69	11.42	10.22	11.52	11.13	11.27
2039	10.25	10.25	11.84	11.57	10.37	11.68	11.28	11.42
2040	10.40	10.40	12.00	11.73	10.52	11.84	11.44	11.58
2041	10.56	10.56	12.16	11.88	10.67	12.00	11.59	11.74
Levelized (2012-2021) (a)	7.17	7.17	8.66	8.43	7.30	8.49	8.13	8.28
Levelized (2012-2026)	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
Levelized (2012-2041) (b)	8.29	8.29	9.81	9.57	8.41	9.65	9.27	9.42

(a) Real (constant $) riskless annual rate of return in %: 2.465%

(b) Values from 2027-2041 extrapolated from Compound Annual Growth Rate (2017-2026)

Exhibit D-2: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Southern New England Assuming Some Avoidable Retail Margin (2011$/MMBtu)

Year	RESIDENTIAL Non Heating	RESIDENTIAL Hot Water annual	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating annual	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2011	5.97	5.97	7.74	7.46	5.91	7.17	6.79	7.10
2012	6.49	6.49	8.21	7.94	6.43	7.64	7.27	7.58
2013	6.70	6.70	8.42	8.15	6.64	7.86	7.49	7.80
2014	6.98	6.98	8.81	8.51	6.92	8.24	7.84	8.15
2015	7.56	7.56	9.28	9.01	7.50	8.71	8.34	8.65
2016	7.59	7.59	9.30	9.04	7.53	8.74	8.37	8.68
2017	7.57	7.57	9.29	9.02	7.51	8.72	8.35	8.66
2018	7.59	7.59	9.32	9.05	7.53	8.75	8.38	8.69
2019	7.64	7.64	9.37	9.10	7.58	8.80	8.43	8.74
2020	7.73	7.73	9.47	9.20	7.67	8.90	8.53	8.84
2021	7.83	7.83	9.58	9.30	7.77	9.01	8.63	8.94
2022	7.96	7.96	9.75	9.46	7.90	9.18	8.80	9.10
2023	8.25	8.25	10.03	9.74	8.19	9.46	9.07	9.38
2024	8.44	8.44	10.20	9.92	8.38	9.63	9.25	9.56
2025	8.51	8.51	10.29	10.00	8.45	9.72	9.33	9.64
2026	8.64	8.64	10.42	10.14	8.58	9.85	9.47	9.78
2027	8.77	8.77	10.56	10.27	8.71	9.99	9.60	9.91
2028	8.90	8.90	10.69	10.40	8.84	10.13	9.74	10.04
2029	9.03	9.03	10.83	10.54	8.97	10.26	9.87	10.18
2030	9.16	9.16	10.97	10.67	9.10	10.40	10.01	10.32
2031	9.30	9.30	11.11	10.81	9.24	10.55	10.15	10.46
2032	9.43	9.43	11.25	10.95	9.37	10.69	10.29	10.60
2033	9.57	9.57	11.40	11.10	9.51	10.84	10.44	10.74
2034	9.71	9.71	11.55	11.24	9.66	10.99	10.58	10.89
2035	9.86	9.86	11.69	11.39	9.80	11.14	10.73	11.03
2036	10.00	10.00	11.85	11.54	9.95	11.29	10.88	11.18
2037	10.15	10.15	12.00	11.69	10.09	11.44	11.03	11.34
2038	10.30	10.30	12.15	11.84	10.24	11.60	11.19	11.49
2039	10.45	10.45	12.31	11.99	10.40	11.76	11.35	11.64
2040	10.61	10.61	12.47	12.15	10.55	11.92	11.50	11.80
2041	10.77	10.77	12.63	12.31	10.71	12.08	11.67	11.96
Levelized (2012-2021) (a)	7.34	7.34	9.08	8.80	7.28	8.51	8.14	8.45
Levelized (2012-2026)	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
Levelized (2012-2041) (b)	8.47	8.47	10.25	9.96	8.41	9.69	9.30	9.61

(a) Real (constant $) riskless annual rate of return in %: 2.465%

(b) Values from 2027-2041 extrapolated from Compound Annual Growth Rate (2017-2026)

Exhibit D-3: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Vermont Gas Systems Assuming Some Avoidable Retail Margin (2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water annual	Heating	All	Non Heating annual	Heating	All	
2011	6.11	6.11	8.48	7.97	5.87	7.68	7.14	7.45
2012	6.55	6.55	8.87	8.37	6.31	8.06	7.54	7.85
2013	6.73	6.73	9.05	8.55	6.49	8.25	7.72	8.04
2014	6.99	6.99	9.41	8.88	6.75	8.61	8.05	8.37
2015	7.46	7.46	9.78	9.28	7.23	8.98	8.45	8.77
2016	7.49	7.49	9.80	9.30	7.26	8.99	8.47	8.79
2017	7.47	7.47	9.79	9.29	7.24	8.98	8.46	8.78
2018	7.50	7.50	9.81	9.31	7.26	9.01	8.48	8.80
2019	7.53	7.53	9.86	9.36	7.30	9.06	8.53	8.85
2020	7.61	7.61	9.95	9.45	7.38	9.14	8.61	8.93
2021	7.70	7.70	10.04	9.54	7.46	9.24	8.70	9.02
2022	7.82	7.82	10.20	9.68	7.58	9.40	8.85	9.17
2023	8.06	8.06	10.44	9.92	7.82	9.63	9.09	9.41
2024	8.22	8.22	10.58	10.07	7.99	9.77	9.23	9.55
2025	8.29	8.29	10.65	10.14	8.05	9.85	9.31	9.63
2026	8.40	8.40	10.77	10.26	8.16	9.97	9.42	9.74
2027	8.51	8.51	10.89	10.37	8.27	10.09	9.54	9.86
2028	8.62	8.62	11.01	10.49	8.38	10.20	9.65	9.97
2029	8.73	8.73	11.12	10.60	8.49	10.32	9.77	10.09
2030	8.84	8.84	11.24	10.72	8.61	10.44	9.89	10.21
2031	8.96	8.96	11.36	10.84	8.72	10.56	10.01	10.33
2032	9.07	9.07	11.49	10.96	8.84	10.69	10.13	10.45
2033	9.19	9.19	11.61	11.08	8.96	10.81	10.25	10.57
2034	9.31	9.31	11.73	11.20	9.08	10.94	10.38	10.69
2035	9.43	9.43	11.86	11.33	9.20	11.06	10.50	10.82
2036	9.56	9.56	11.99	11.45	9.32	11.19	10.63	10.94
2037	9.68	9.68	12.11	11.58	9.45	11.32	10.76	11.07
2038	9.81	9.81	12.24	11.70	9.57	11.45	10.89	11.20
2039	9.93	9.93	12.38	11.83	9.70	11.59	11.02	11.33
2040	10.06	10.06	12.51	11.97	9.83	11.72	11.15	11.46
2041	10.19	10.19	12.64	12.10	9.97	11.86	11.29	11.60
Levelized (2012-2021) (a)	7.28	7.28	9.61	9.11	7.04	8.81	8.28	8.60
Levelized (2012-2026)	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
Levelized (2012-2041) (b)	8.25	8.25	10.62	10.10	8.01	9.82	9.28	9.59

(a) Real (constant $) riskless annual rate of return in %: 2.465%

(b) Values from 2027-2041 extrapolated from Compound Annual Growth Rate (2017-2026)

Exhibit D-4: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Northern and Central New England Assuming No Avoidable Retail Margin (2011$/MMBtu)

Year	END-USE LOAD TYPE Heating	Non-Heating	All	Annual Average	Annual Henry Hub Price
2011	5.96	5.30	5.76	5.30	4.37
2012	6.42	5.81	6.24	5.81	4.91
2013	6.63	6.02	6.45	6.02	5.10
2014	7.01	6.30	6.80	6.30	5.29
2015	7.48	6.86	7.29	6.86	5.91
2016	7.50	6.90	7.32	6.90	5.96
2017	7.48	6.87	7.30	6.87	5.93
2018	7.51	6.90	7.33	6.90	5.95
2019	7.57	6.94	7.38	6.94	5.98
2020	7.66	7.03	7.47	7.03	6.06
2021	7.77	7.13	7.58	7.13	6.16
2022	7.94	7.26	7.74	7.26	6.25
2023	8.21	7.54	8.01	7.54	6.52
2024	8.38	7.73	8.18	7.73	6.72
2025	8.46	7.81	8.27	7.81	6.78
2026	8.60	7.93	8.40	7.93	6.89
2027	8.73	8.05	8.53	8.05	7.04
2028	8.87	8.18	8.66	8.18	7.20
2029	9.01	8.31	8.80	8.31	7.41
2030	9.15	8.45	8.94	8.45	7.33
2031	9.29	8.58	9.08	8.58	7.34
2032	9.43	8.72	9.22	8.72	7.49
2033	9.58	8.86	9.36	8.86	7.63
2034	9.73	9.00	9.51	9.00	7.66
2035	9.88	9.14	9.66	9.14	7.83
2036	10.03	9.29	9.81	9.29	7.96
2037	10.19	9.44	9.96	9.44	8.10
2038	10.35	9.59	10.12	9.59	8.24
2039	10.51	9.74	10.28	9.74	8.37
2040	10.67	9.90	10.44	9.90	8.52
2041	10.84	10.06	10.60	10.06	8.66
Levelized (2012-2021)	7.28	6.65	7.09	6.65	5.70
Levelized (2012-2026)	7.58	6.94	7.39	6.94	5.97
Levelized (2012-2041)	8.44	7.77	8.24	7.77	6.69

15 Years (2012 - 2026) at the Real (constant $) Discont Rate 2.465%
Values for 2027-2041, extrapolated from CAGR of 2017-2026.
Henry Hub Price for 2036-2041, extrapolated from CAGR of 2017-2026

Exhibit D-5: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Southern New England Assuming No Avoidable Retail Margin (2011$/MMBtu)

	END-USE LOAD TYPE				Annual
Year	Heating	Non-Heating	All	Annual Average	Henry Hub Price
2011	6.16	5.37	5.92	5.37	4.37
2012	6.63	5.89	6.41	5.89	4.91
2013	6.84	6.10	6.62	6.10	5.10
2014	7.23	6.38	6.97	6.38	5.29
2015	7.70	6.95	7.48	6.95	5.91
2016	7.72	6.99	7.50	6.99	5.96
2017	7.71	6.97	7.49	6.97	5.93
2018	7.74	6.99	7.51	6.99	5.95
2019	7.79	7.03	7.56	7.03	5.98
2020	7.89	7.13	7.66	7.13	6.06
2021	7.99	7.23	7.77	7.23	6.16
2022	8.17	7.36	7.93	7.36	6.25
2023	8.45	7.64	8.21	7.64	6.52
2024	8.62	7.84	8.38	7.84	6.72
2025	8.70	7.91	8.47	7.91	6.78
2026	8.84	8.04	8.60	8.04	6.89
2027	8.96	8.15	8.72	8.15	7.04
2028	9.08	8.26	8.83	8.26	7.20
2029	9.20	8.37	8.95	8.37	7.41
2030	9.33	8.49	9.07	8.49	7.33
2031	9.45	8.61	9.20	8.61	7.34
2032	9.58	8.73	9.32	8.73	7.49
2033	9.70	8.85	9.45	8.85	7.63
2034	9.83	8.97	9.58	8.97	7.66
2035	9.97	9.09	9.70	9.09	7.83
2036	10.10	9.22	9.84	9.22	7.95
2037	10.23	9.35	9.97	9.35	8.06
2038	10.37	9.48	10.10	9.48	8.18
2039	10.51	9.61	10.24	9.61	8.30
2040	10.65	9.74	10.38	9.74	8.42
2041	10.79	9.88	10.52	9.88	8.54
Levelized (2012-2021)	7.50	6.74	7.27	6.74	5.70
Levelized (2012-2026)	7.81	7.04	7.57	7.04	5.97
Levelized (2012-2041)	8.62	7.81	8.38	7.81	6.68

15 Years (2012 - 2026) at the Real (constant $) Discont Rate 2.465%
Values for 2027-2041, extrapolated from CAGR of 2017-2026.
Henry Hub Price for 2036-2041, extrapolated from CAGR of 2017-2026

Exhibit D-6: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Vermont Gas System Assuming No Avoidable Retail Margin (2011$/MMBtu)

Year	END-USE LOAD TYPE Heating	Non-Heating	All	Annual Average	Annual Henry Hub Price
2011	7.23	5.63	6.75	5.63	4.37
2012	7.62	6.07	7.15	6.07	4.91
2013	7.80	6.25	7.34	6.25	5.10
2014	8.16	6.51	7.66	6.51	5.29
2015	8.53	6.99	8.07	6.99	5.91
2016	8.55	7.02	8.09	7.02	5.96
2017	8.54	7.00	8.08	7.00	5.93
2018	8.56	7.02	8.10	7.02	5.95
2019	8.61	7.06	8.15	7.06	5.98
2020	8.70	7.14	8.23	7.14	6.06
2021	8.79	7.22	8.32	7.22	6.16
2022	8.95	7.34	8.47	7.34	6.25
2023	9.18	7.58	8.70	7.58	6.52
2024	9.32	7.75	8.85	7.74	6.72
2025	9.40	7.81	8.92	7.81	6.78
2026	9.52	7.92	9.04	7.92	6.89
2027	9.64	8.03	9.16	8.03	7.04
2028	9.76	8.14	9.27	8.14	7.20
2029	9.88	8.25	9.39	8.25	7.41
2030	10.00	8.37	9.51	8.37	7.33
2031	10.12	8.48	9.63	8.48	7.34
2032	10.24	8.60	9.75	8.60	7.49
2033	10.37	8.72	9.87	8.72	7.63
2034	10.49	8.84	10.00	8.84	7.66
2035	10.62	8.96	10.12	8.96	7.83
2036	10.75	9.09	10.25	9.09	7.96
2037	10.88	9.21	10.38	9.21	8.10
2038	11.02	9.34	10.51	9.34	8.24
2039	11.15	9.47	10.65	9.47	8.37
2040	11.29	9.60	10.78	9.60	8.52
2041	11.42	9.74	10.92	9.73	8.66
Levelized (2012-2021)	8.36	6.80	7.89	6.80	5.70
Levelized (2012-2026)	8.63	7.06	8.16	7.06	5.97
Levelized (2012-2041)	9.37	7.77	8.89	7.77	6.69

15 Years (2012 - 2026) at the Real (constant $) Discont Rate 2.465%
Values for 2027-2041, extrapolated from CAGR of 2017-2026.
Henry Hub Price for 2036-2041, extrapolated from CAGR of 2017-2026

Exhibit D-7: Avoided Cost of Gas Delivered to LDC's by Month: Northern and Central New England via Tennessee Gas Pipeline ($2011/Dekatherm)

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	PEAK DAY (a)	Annual Henry Hub Price (2011$)
Demand Cash Cost (b)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.565	$0.680	$0.917	$0.667	$0.541	$84.786	
Variable Cash Cost (c)	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.190	$0.380	$0.441	$0.428	$0.338	$0.957	
Ratio of Gas Purchased to Delivered	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.089	1.095	1.105	1.099	1.092	1.093	
2011	4.572	4.587	4.637	4.698	4.741	4.760	4.819	5.664	6.076	6.653	6.293	6.056	90.370	4.37
2012	5.115	5.133	5.189	5.257	5.305	5.327	5.393	6.268	6.693	7.031	6.651	6.358	90.940	4.91
2013	5.310	5.328	5.386	5.457	5.507	5.530	5.599	6.484	6.914	7.246	6.861	6.563	91.143	5.10
2014	5.500	5.519	5.580	5.653	5.705	5.728	5.800	6.695	7.130	7.748	7.368	7.122	91.343	5.29
2015	6.132	6.153	6.220	6.303	6.360	6.387	6.466	7.397	7.847	8.071	7.664	7.331	92.004	5.91
2016	6.181	6.202	6.270	6.353	6.411	6.437	6.518	7.451	7.902	8.073	7.663	7.318	92.055	5.96
2017	6.149	6.170	6.238	6.320	6.378	6.404	6.484	7.415	7.866	8.072	7.664	7.327	92.022	5.93
2018	6.171	6.191	6.260	6.342	6.401	6.427	6.507	7.440	7.891	8.102	7.694	7.357	92.044	5.95
2019	6.201	6.222	6.290	6.373	6.432	6.458	6.539	7.473	7.925	8.172	7.764	7.434	92.076	5.98
2020	6.286	6.307	6.377	6.461	6.520	6.547	6.629	7.568	8.021	8.273	7.863	7.533	92.165	6.06
2021	6.381	6.402	6.473	6.559	6.619	6.646	6.729	7.673	8.129	8.378	7.966	7.633	92.264	6.16
2022	6.474	6.496	6.568	6.655	6.716	6.743	6.828	7.777	8.235	8.601	8.191	7.879	92.362	6.25
2023	6.749	6.772	6.846	6.937	7.001	7.030	7.118	8.082	8.547	8.861	8.442	8.116	92.650	6.52
2024	6.951	6.975	7.052	7.145	7.211	7.241	7.332	8.307	8.777	8.996	8.569	8.221	92.862	6.72
2025	7.014	7.038	7.116	7.210	7.277	7.307	7.398	8.377	8.848	9.095	8.668	8.324	92.928	6.78
2026	7.122	7.146	7.225	7.321	7.388	7.418	7.512	8.496	8.970	9.246	8.817	8.476	93.040	6.89
Levelized 2012-2026(d)	6.191	6.212	6.281	6.364	6.422	6.448	6.529	7.463	7.914	8.202	7.795	7.474	92.066	
Simple Average (2012-2026)	6.249	6.270	6.339	6.423	6.482	6.509	6.590	7.527	7.980	8.264	7.856	7.533	92.126	

(a) Peak day avoided cost is calculated based on currently effective rates, which are the basis for the monthly avoided costs.
(b) The cash costs paid to pipelines as demand charges to reserve transportation and storage capacity.
(c) The variable cash cost is primarily the cash paid to pipelines for using the pipelines to transport and store natural gas plus the demand charges at 100% load factor to move gas into storage.
(d) Real (constant $) riskless annual rate of return in %: 2.465%

Exhibit D-8: Avoided Cost of Gas Delivered to LDC's by Month: Southern New England via Texas Eastern and Algonquin Gas Pipelines ($2011/Dekatherm)

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	PEAK DAY (a)	Annual Henry Hub Price (2011$)
Demand Cash Cost (b)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.831	$0.960	$1.225	$0.910	$0.777	$100.126	
Variable Cash Cost (c)	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.085	$0.260	$0.315	$0.303	$0.221	$0.792	
Ratio of Gas Purchased to Delivered	1.084	1.084	1.084	1.084	1.084	1.084	1.084	1.091	1.117	1.130	1.124	1.113	1.136	
2011	4.523	4.539	4.590	4.651	4.694	4.714	4.774	5.831	6.338	6.949	6.522	6.272	105.729	4.37
2012	5.074	5.091	5.148	5.217	5.266	5.288	5.355	6.436	6.967	7.337	6.890	6.582	106.321	4.91
2013	5.271	5.289	5.348	5.420	5.470	5.493	5.563	6.653	7.193	7.557	7.105	6.791	106.533	5.10
2014	5.464	5.482	5.544	5.618	5.671	5.694	5.767	6.865	7.413	8.068	7.620	7.359	106.740	5.29
2015	6.103	6.124	6.192	6.275	6.334	6.360	6.441	7.567	8.144	8.401	7.926	7.574	107.427	5.91
2016	6.152	6.173	6.242	6.326	6.385	6.412	6.493	7.621	8.201	8.403	7.925	7.561	107.481	5.96
2017	6.120	6.141	6.210	6.293	6.352	6.378	6.459	7.586	8.164	8.402	7.926	7.570	107.446	5.93
2018	6.142	6.163	6.232	6.316	6.375	6.401	6.483	7.610	8.189	8.433	7.956	7.601	107.470	5.95
2019	6.172	6.193	6.263	6.347	6.406	6.433	6.515	7.643	8.224	8.504	8.028	7.679	107.502	5.98
2020	6.258	6.280	6.350	6.436	6.496	6.523	6.606	7.738	8.323	8.607	8.129	7.780	107.595	6.06
2021	6.354	6.376	6.448	6.534	6.596	6.623	6.707	7.844	8.432	8.715	8.234	7.882	107.698	6.16
2022	6.449	6.471	6.544	6.632	6.694	6.721	6.807	7.948	8.540	8.942	8.463	8.132	107.800	6.25
2023	6.727	6.750	6.826	6.918	6.982	7.011	7.101	8.253	8.858	9.208	8.720	8.373	108.099	6.52
2024	6.932	6.956	7.034	7.128	7.195	7.225	7.317	8.478	9.093	9.346	8.851	8.481	108.319	6.72
2025	6.996	7.020	7.099	7.194	7.261	7.292	7.384	8.549	9.166	9.448	8.952	8.586	108.388	6.78
2026	7.104	7.129	7.209	7.306	7.374	7.405	7.499	8.668	9.290	9.601	9.103	8.741	108.505	6.89
Levelized 2012-2026 (d)	6.163	6.184	6.253	6.337	6.397	6.423	6.505	7.633	8.213	8.534	8.060	7.719	107.492	
Simple Average (2012-2026)	6.221	6.243	6.313	6.397	6.457	6.484	6.566	7.697	8.280	8.598	8.122	7.779	107.555	

(a) Peak day avoided cost is calculated based on the Legacy Rates, which are the basis for the monthly avoided costs.
(b) The cash costs paid to pipelines as demand charges to reserve transportation and storage capacity.
(c) The variable cash cost is primarily the cash paid to pipelines for using the pipelines to transport and store natural gas plus the demand charges at 10% load factor to move gas into storage.
(d) Real (constant $) Discount Rate %: 2.465%

Exhibit D-9: Avoided Cost of Gas Delivered to LDCs by Month: Vermont Gas System via TransCanada Gas Pipelines ($2011/Dekatherm)

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	PEAK DAY (a) Rates	Annual Henry Hub Price
Demand Cash Cost (b)	$0.059	$0.000	$0.000	$0.000	$0.000	$0.000	$0.009	$1.848	$1.796	$2.303	$1.931	$1.757	$191.489	
Variable Cash Cost (c)	$0.145	$0.171	$0.171	$0.171	$0.171	$0.171	$0.160	$1.141	$1.288	$1.271	$1.367	$0.745	$4.055	
Ratio of Gas Purchased to Delivered	1.027	1.032	1.032	1.032	1.032	1.032	1.030	1.042	1.039	1.037	1.039	1.031	1.077	
2011	4.189	4.013	4.056	4.109	4.146	4.163	4.283	7.232	7.605	8.483	8.046	7.280	$199.65	4.369
2012	4.667	4.486	4.534	4.594	4.635	4.654	4.784	7.749	8.146	8.771	8.337	7.516	$200.16	4.907
2013	4.838	4.655	4.706	4.767	4.810	4.830	4.963	7.934	8.340	8.960	8.521	7.697	$200.34	5.099
2014	5.006	4.820	4.873	4.937	4.981	5.002	5.138	8.115	8.530	9.463	8.998	8.229	$200.51	5.287
2015	5.562	5.369	5.428	5.499	5.549	5.572	5.720	8.716	9.159	9.671	9.217	8.361	$201.10	5.912
2016	5.605	5.412	5.471	5.543	5.593	5.616	5.765	8.762	9.208	9.661	9.210	8.343	$201.15	5.960
2017	5.577	5.384	5.443	5.514	5.565	5.587	5.736	8.732	9.176	9.668	9.215	8.356	$201.12	5.928
2018	5.596	5.403	5.462	5.534	5.584	5.607	5.756	8.753	9.198	9.695	9.241	8.383	$201.14	5.950
2019	5.622	5.429	5.488	5.560	5.611	5.634	5.783	8.781	9.228	9.764	9.307	8.455	$201.16	5.980
2020	5.697	5.503	5.563	5.636	5.688	5.711	5.862	8.862	9.313	9.856	9.396	8.543	$201.24	6.064
2021	5.781	5.586	5.647	5.721	5.773	5.797	5.949	8.953	9.407	9.948	9.486	8.632	$201.33	6.158
2022	5.863	5.667	5.729	5.804	5.857	5.881	6.035	9.041	9.500	10.170	9.696	8.865	$201.42	6.250
2023	6.104	5.905	5.970	6.049	6.104	6.129	6.288	9.303	9.774	10.390	9.912	9.067	$201.67	6.521
2024	6.283	6.081	6.148	6.229	6.286	6.312	6.475	9.495	9.976	10.490	10.014	9.148	$201.86	6.722
2025	6.338	6.136	6.204	6.285	6.343	6.369	6.533	9.555	10.039	10.584	10.104	9.243	$201.92	6.784
2026	6.433	6.230	6.298	6.381	6.439	6.466	6.632	9.657	10.145	10.723	10.238	9.381	$202.02	6.890
Levelized (d)	5.614	5.421	5.480	5.552	5.603	5.626	5.775	8.772	9.218	9.800	9.340	8.496	$201.16	
Simple Average	5.665	5.471	5.531	5.604	5.655	5.678	5.828	8.827	9.276	9.854	9.393	8.548	$201.21	

(a) Peak day avoided cost is calculated based using gas stored in underground storage for one peak day. Thus, the annual demand charges for transporting gas from storage to Phillipsburg are charged to that one peak day.
(b) The cash costs paid to pipelines as demand charges to reserve transportation and storage capacity.
(c) The variable cash cost is primarily the cash paid to pipelines for using the pipelines to transport and store natural gas, usage charges, plus the demand charges at 100% load factor to move gas into storage.
(d) Real (constant $) riskless annual rate of return i 2.465% (2012-2026)

Appendix E: Avoided Costs of Other Fuels

Table of Exhibits

Exhibit E-1: AESC 2011 Forecast Weighted Average Avoided Cost of Petroleum Fuels by Sector and Other Fuels

	Fuel Oils							Other Fuels		
	Residential	Commercial			Industrial			Residential		
Year	Distillate Fuel Oil/ Biofuel	Distillate Fuel Oil/ Biofuel	Residual Fuel	Sum	Distillate Fuel Oil/ Biofuel	Residual Fuel Oil	Sum	Wood	Kerosene	Propane
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$
2011	$27.00	$19.85	$3.06	$22.90	$10.27	$9.48	$19.75	10.08	26.75	41.28
2012	$26.22	$18.74	$3.55	$22.29	$10.62	$9.24	$19.86	9.78	25.97	39.36
2013	$25.44	$18.17	$3.66	$21.83	$10.87	$8.95	$19.82	9.49	25.20	37.77
2014	$24.69	$17.58	$3.72	$21.30	$10.98	$8.61	$19.60	9.21	24.46	36.55
2015	$24.18	$17.14	$3.82	$20.95	$10.97	$8.40	$19.37	9.02	23.96	35.61
2016	$24.14	$17.22	$3.73	$20.96	$11.05	$8.29	$19.34	9.01	23.92	34.74
2017	$23.94	$17.03	$3.77	$20.80	$11.03	$8.21	$19.24	8.93	23.72	34.07
2018	$24.64	$17.49	$3.95	$21.44	$11.43	$8.44	$19.88	9.19	24.41	34.68
2019	$25.09	$17.76	$4.15	$21.91	$11.73	$8.70	$20.43	9.36	24.86	34.95
2020	$25.47	$17.96	$4.28	$22.24	$11.96	$8.79	$20.75	9.50	25.23	35.19
2021	$25.62	$18.03	$4.37	$22.41	$12.06	$8.91	$20.96	9.56	25.38	35.44
2022	$25.83	$18.23	$4.45	$22.68	$12.19	$9.06	$21.25	9.64	25.59	35.65
2023	$26.17	$18.38	$4.55	$22.92	$12.28	$9.19	$21.47	9.76	25.92	35.95
2024	$26.36	$18.44	$4.64	$23.08	$12.34	$9.30	$21.64	9.84	26.11	36.23
2025	$26.67	$18.62	$4.74	$23.35	$12.53	$9.39	$21.92	9.95	26.42	36.50
2026	$26.95	$18.75	$4.81	$23.56	$12.68	$9.42	$22.10	10.06	26.70	36.66
2027	$27.31	$18.95	$4.94	$23.89	$12.88	$9.57	$22.44	10.19	27.06	36.96
2028	$27.67	$19.16	$5.08	$24.23	$13.08	$9.71	$22.79	10.33	27.41	37.26
2029	$28.04	$19.36	$5.22	$24.56	$13.28	$9.86	$23.15	10.46	27.78	37.57
2030	$28.41	$19.57	$5.36	$24.91	$13.49	$10.02	$23.50	10.60	28.14	37.88
2031	$28.79	$19.78	$5.51	$25.25	$13.70	$10.17	$23.87	10.74	28.52	38.19
2032	$29.17	$20.00	$5.66	$25.61	$13.91	$10.33	$24.24	10.88	28.90	38.50
2033	$29.55	$20.21	$5.81	$25.96	$14.13	$10.49	$24.62	11.03	29.28	38.81
2034	$29.95	$20.43	$5.97	$26.33	$14.35	$10.65	$25.00	11.17	29.67	39.13
2035	$30.34	$20.65	$6.13	$26.69	$14.57	$10.81	$25.39	11.32	30.06	39.45
2036	$30.74	$20.87	$6.30	$27.06	$14.80	$10.98	$25.78	11.47	30.46	39.77
2037	$31.15	$21.10	$6.47	$27.44	$15.03	$11.15	$26.18	11.62	30.86	40.10
2038	$31.56	$21.33	$6.65	$27.82	$15.27	$11.32	$26.59	11.78	31.27	40.43
2039	$31.98	$21.56	$6.83	$28.21	$15.51	$11.50	$27.00	11.93	31.68	40.76
2040	$32.41	$21.79	$7.02	$28.61	$15.75	$11.67	$27.42	12.09	32.10	41.09
2041	$32.83	$22.02	$7.21	$29.01	$15.99	$11.85	$27.85	12.25	32.53	41.43
Levelized Costs										
2012-2021	$24.95	$17.72	$3.88	$21.60	$11.24	$8.66	$19.90	$9.31	$24.71	$35.92
2012-2026	$25.37	$17.94	$4.10	$22.05	$11.58	$8.84	$20.42	$9.47	$25.13	$36.00
2012-2041	$27.19	$18.93	$4.86	$23.75	$12.69	$9.56	$22.25	$10.15	$26.94	$37.23

Notes

Calculation based on fuel oil forecast percentages by sector multiplied by fuel oil forecast price by sector

2027-2041 costs extrapolated based on 2017-2026 compound annual growth rate

Exhibit E-2: Crude Oil and Fuel Prices by Sector in New England - AESC 2009 Forecast (2011$)

	Crude Oil Prices				Fuel Prices for Electric Generation in New England			Residential			Commercial			Industrial		
Year	AEO 2010 Forecast Imported Low Sulfur Crude	WTI NYMEX Futures Swaps as of March 18 2011	AESC 2011 Forecast Imported Low-Sulfur Crude	AESC 2011 Forecast Imported Low-Sulfur Crude	Distillate Fuel Oil	Residual Fuel Oil	Steam Coal	Distillate Fuel Oil	Kerosene	Cord Wood	Distillate Fuel Oil	Residual Fuel	Kerosene	Distillate Fuel Oil	Residual Fuel Oil	Kerosene
	$/bbl	$/bbl	$/bbl	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$
2011	75.10	105.96	108.07	18.63	21.19	13.22	3.16	27.00	26.75	10.08	24.43	16.30	26.84	24.55	16.30	24.02
2012	81.62	102.67	107.40	18.52	20.83	13.56	3.13	26.22	25.97	9.78	23.84	16.60	26.20	23.97	16.60	23.45
2013	88.13	98.31	106.73	18.40	20.42	13.75	3.08	25.44	25.20	9.49	23.25	16.73	25.56	23.39	16.73	22.88
2014	93.45	95.31	106.06	18.29	19.94	13.78	3.05	24.69	24.46	9.21	22.65	16.62	24.89	22.79	16.62	22.30
2015	97.15	93.40	105.39	18.17	19.62	13.58	3.05	24.18	23.96	9.02	22.38	16.30	24.59	22.63	16.30	22.14
2016	100.98	92.01	104.72	18.06	19.74	13.53	2.97	24.14	23.92	9.01	22.38	16.21	24.59	22.61	16.21	22.12
2017	104.05	90.69	104.05	17.94	19.67	13.49	2.99	23.94	23.72	8.93	22.22	16.15	24.42	22.43	16.15	21.95
2018	107.32	89.64	107.32	18.50	20.33	13.98	2.91	24.64	24.41	9.19	22.91	16.70	25.18	23.13	16.70	22.63
2019	109.44	88.71	109.44	18.87	20.77	14.34	2.92	25.09	24.86	9.36	23.36	17.32	25.67	23.57	17.32	23.06
2020	111.30		111.30	19.19	21.13	14.48	2.77	25.47	25.23	9.50	23.74	17.55	26.10	23.97	17.55	23.45
2021	112.58		112.58	19.41	21.27	14.72	2.76	25.62	25.38	9.56	23.92	17.77	26.29	24.17	17.77	23.65
2022	114.02		114.02	19.66	21.47	14.91	2.73	25.83	25.59	9.64	24.21	18.01	26.61	24.53	18.01	24.00
2023	115.45		115.45	19.91	21.79	15.13	2.72	26.17	25.92	9.76	24.48	18.25	26.90	24.74	18.25	24.21
2024	116.80		116.80	20.14	21.98	15.35	2.71	26.36	26.11	9.84	24.62	18.47	27.06	24.85	18.47	24.32
2025	118.30		118.30	20.40	22.27	15.55	2.71	26.67	26.42	9.95	24.94	18.69	27.41	25.17	18.69	24.63
2026	119.87		119.87	20.67	22.55	15.62	2.72	26.95	26.70	10.06	25.21	18.78	27.71	25.44	18.78	24.90
Levelized Costs																
2012-2016				18.29	20.12	13.64	3.06	24.96	24.73	9.31	22.92	16.50	25.19	23.09	16.50	22.60
2012-2021				18.51	20.35	13.90	2.97	24.95	24.71	9.31	23.06	16.77	25.34	23.25	16.77	22.75
2012-2026				18.99	20.84	14.31	2.90	25.37	25.13	9.47	23.53	17.26	25.86	23.75	17.26	23.24

Notes

Crude Oil forecasts based on EIA historical and projected values from AEO 2009 Table A12; West Texas Intermediate NYMEX prices as of March 18, 2011

Electric Generation Forecast based on AEO 2011 Table S11; Sector fuel price forecast based on low-sulfur fuel price ratios relative to historic and forecast crude oil prices

Exhibit E-3: Percentage of AESC 2011 Forecast Mix of Petroleum Related Fuels by Grade by Sector

	Residential	Commercial		Industrial	
Year	Distillate Fuel Oil	Distillate Fuel Oil	Residual Fuel	Distillate Fuel Oil	Residual Fuel Oil
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	Percent	Percent	Percent	Percent	Percent
2011	100%	81%	19%	42%	58%
2012	100%	79%	21%	44%	56%
2013	100%	78%	22%	46%	54%
2014	100%	78%	22%	48%	52%
2015	100%	77%	23%	48%	52%
2016	100%	77%	23%	49%	51%
2017	100%	77%	23%	49%	51%
2018	100%	76%	24%	49%	51%
2019	100%	76%	24%	50%	50%
2020	100%	76%	24%	50%	50%
2021	100%	75%	25%	50%	50%
2022	100%	75%	25%	50%	50%
2023	100%	75%	25%	50%	50%
2024	100%	75%	25%	50%	50%
2025	100%	75%	25%	50%	50%
2026	100%	74%	26%	50%	50%

Notes

Calculations based on AEO 2010 Supplemental Table One for New England Fuel and Sector Consumption
Percentages based on 2010 fuel oil forecast of consumption by sector

Exhibit E-4: Pollutant Emission Values (2011$/MMBtu)

	Residential				Commercial				Industrial			
	SO_2	NO_x	CO_2	CO_2 at $80/ton	SO_2	NO_x	CO_2	CO_2 at $80/ton	SO_2	NO_x	CO_2	CO_2 at $80/ton
2011	$0.0003	$0.0148	$0.1635	$6.92	$0.0003	$0.0197	$0.1550	$6.56	$0.0006	$0.0197	$0.1521	$6.44
2012	$0.0002	$0.0095	$0.1635	$6.92	$0.0002	$0.0127	$0.1550	$6.56	$0.0005	$0.0127	$0.1521	$6.44
2013	$0.0001	$0.0089	$0.1635	$6.92	$0.0001	$0.0119	$0.1550	$6.56	$0.0003	$0.0119	$0.1521	$6.44
2014	$0.0001	$0.0091	$0.1635	$6.92	$0.0001	$0.0121	$0.1550	$6.56	$0.0002	$0.0121	$0.1521	$6.44
2015	$0.0001	$0.0092	$0.1635	$6.92	$0.0001	$0.0123	$0.1550	$6.56	$0.0002	$0.0123	$0.1521	$6.44
2016	$0.0001	$0.0094	$0.1635	$6.92	$0.0001	$0.0125	$0.1550	$6.56	$0.0002	$0.0125	$0.1521	$6.44
2017	$0.0001	$0.0096	$0.1635	$6.92	$0.0001	$0.0128	$0.1550	$6.56	$0.0002	$0.0128	$0.1521	$6.44
2018	$0.0001	$0.0098	$1.3235	$6.92	$0.0001	$0.0130	$1.2546	$6.56	$0.0002	$0.0130	$1.2317	$6.44
2019	$0.0001	$0.0100	$1.5808	$6.92	$0.0001	$0.0133	$1.4986	$6.56	$0.0002	$0.0133	$1.4711	$6.44
2020	$0.0001	$0.0102	$1.8381	$6.92	$0.0001	$0.0135	$1.7425	$6.56	$0.0002	$0.0135	$1.7106	$6.44
2021	$0.0001	$0.0104	$2.0955	$6.92	$0.0001	$0.0138	$1.9865	$6.56	$0.0002	$0.0138	$1.9501	$6.44
2022	$0.0001	$0.0106	$2.3528	$6.92	$0.0001	$0.0141	$2.2304	$6.56	$0.0002	$0.0141	$2.1896	$6.44
2023	$0.0001	$0.0108	$2.6101	$6.92	$0.0001	$0.0144	$2.4744	$6.56	$0.0002	$0.0144	$2.4291	$6.44
2024	$0.0001	$0.0110	$2.8675	$6.92	$0.0001	$0.0147	$2.7183	$6.56	$0.0002	$0.0147	$2.6686	$6.44
2025	$0.0001	$0.0113	$3.1248	$6.92	$0.0001	$0.0150	$2.9623	$6.56	$0.0002	$0.0150	$2.9081	$6.44
2026	$0.0001	$0.0114	$3.3822	$6.92	$0.0001	$0.0153	$3.2062	$6.56	$0.0002	$0.0153	$3.1476	$6.44
Levelized (2011$/MMBtu)												
5 year (2012-16)	$0.0001	$0.0092	$0.1635	$6.92	$0.0001	$0.0123	$0.1550	$6.56	$0.0003	$0.0123	$0.1521	$6.44
10 year (2012-21)	$0.0001	$0.0096	$0.7343	$6.92	$0.0001	$0.0128	$0.6961	$6.56	$0.0003	$0.0128	$0.6834	$6.44
15 year (2012-26)	$0.0001	$0.0100	$1.3572	$6.92	$0.0001	$0.0133	$1.2866	$6.56	$0.0003	$0.0133	$1.2631	$6.44

Notes

Based on pollution emission rates for Number 2 fuel oil

Pollutant values based on emission allowance prices detailed in Exhibit 2-4 and Exhibit 6-56.